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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE PETITION OF IDAHO POWER COMPANY FOR MODIFICATION OF THE LOAD GROWTH ADJUSTMENT FACTOR WITHIN THE POWER COST ADJUSTMENT (PAC) METHODOLOGY.	)	**CASE NO. IPC-E-06-8**

DIRECT TESTIMONY OF KEITH HESSING

IDAHO PUBLIC UTILITIES COMMISSION

SEPTEMBER 14, 2006

Q. Please state your name and business address for the record.

A. My name is Keith D. Hessing and my business address is 472 West Washington Street, Boise, Idaho.

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

A. I am employed by the Idaho Public Utilities Commission as a Public Utilities Engineer.

Q. What is your educational and experience background?

A. I am a Registered Professional Engineer in the State of Idaho. I received a Bachelor of Science Degree in Civil Engineering from the University of Idaho in 1974. Since then, I worked six years for the Idaho Department of Water Resources, and two years for Morrison-Knudsen. I have been continuously employed at the Commission since August 1983.

As a member of the Commission Staff, my primary areas of responsibility have been electric utility power supply, revenue allocation and rate design.

Q. What is the purpose of your testimony in this proceeding?

A. I will address the Company's filing to reduce the load growth adjustment multiplier, sometimes called the Expense Adjustment Rate for Growth (EARG), which is used in the Power Cost Adjustment (PCA) true up calculation.

Q. As a member of the Commission Staff have you worked on Idaho Power Company's annual PCA mechanism since its inception in 1992?

A. Yes I have.

Q. What is the purpose of the Company's PCA?

A. The PCA was created to address the problem of fluctuating water conditions that caused widely varying power supply costs.

Q. What does the load growth adjustment multiplier do in the PCA true up calculation?

A. When the Company's load grows between general rate cases the power supply costs of serving that load growth are captured in the PCA true up mechanism. All or part of those costs are removed from the mechanism by applying the multiplier to the amount of load growth and removing the resulting cost from actual power supply costs incurred. Any costs removed in this manner are not available for deferral as part of the PCA true up and, therefore, will not be recovered in PCA rates.

Q. Please provide an example of this calculation and the associated adjustment.

A. Staff Exhibit No. 101, pages 1 and 2, shows the PCA true up calculations from the Company's last PCA case, Case No. IPC-E-06-7. The expense adjustment associated with load growth for the month of April 2005 is

calculated on lines 9 through 12. Lines 9 and 10 show the actual load and the normalized load. Line 11 calculates the load growth and line 12 is the product of the load growth and the load growth adjustment multiplier. (1,002,528 MWh - 974,066 MWh = 28,462 MWh) (28,462 MWh x 16.84 $/MWh = $479,300) Line 12 shows the calculated expense adjustment for April to be $479,300. This amount is carried to line 23 where it is shown as a reduction to actual power supply expense. Page 2, lines 12 and 23, shows the total adjustment for the PCA year to be $10,291,160.

Q. What does the Commission need to decide in this proceeding?

A. There are two parts to the decision that the Commission is being asked to make in this case. The first part is a matter of policy. Should Idaho Power Company be allowed to recover the variable costs of power supply associated with load growth that occur between general rate cases through the PCA mechanism? The second question follows. What is the appropriate load growth adjustment multiplier that accomplishes the policy decision?

Q. Please provide some history and background information on Idaho Power's PCA mechanism.

A. Prior to PCA implementation, if the Company's load grew, the Company sold the additional energy at

approved retail rates and the Company incurred costs in serving the new load. The revenues and costs associated with serving load growth were not necessarily balanced. If costs exceeded revenues, the Company could file a general rate case to increase rates to cover the costs on a prospective basis. If the cost of serving load growth did not exceed the costs embedded in rates, no rate increase would be justified.

Q. Please discuss Idaho Power Company's initial PCA filing.

A. Idaho Power Company filed for a PCA in 1992 and it was approved and implemented in 1993 with some modification. Idaho Power's 1992 PCA filing was made to address the problem of fluctuating water conditions that caused widely varying power supply costs. When water conditions were poor, power supply costs were higher than what was authorized for recovery in rates. A general rate case provided no relief from high power supply costs associated with below normal water conditions since water conditions and power supply costs are normalized in a general rate case.

Staff observed that in the Company's original PCA proposal, variations from the normalized costs of power supply were due to water conditions and power supply cost increases caused by load growth. Staff believed that load

growth costs could be significant and that load growth costs were not the kind of costs that the PCA should recover. Staff proposed a load growth adjustment mechanism in the PCA that removed actual power supply costs associated with load growth by multiplying the amount of load growth by the marginal cost of power supply and subtracting the result from actual power supply costs. Staff approximated the marginal cost of power supply as 16.84 $/MWh which was the average of the variable costs of Valmy and Boardman, the Company's two highest operating cost resources at that time. In that case Staff also argued that without the adjustment the Company would double recover the normalized cost of power supply because it was included in base rates and in actual booked power supply costs that accumulated in the PCA true up mechanism.

The Commission accepted Staff's load growth adjustment to the PCA in its final Order.

> **We find that the net power supply costs associated with serving differences in load between normal and actual should be removed from the PCA.** We adopt the method proposed by Staff for making this adjustment; it was the only method proposed. We agree with Staff that Idaho Power's proposal unduly broadens the scope of this proceeding, which is simply to devise a mechanism for the recovery of power supply costs that include the sum of fuel costs, non-firm energy purchases and CSPP costs less revenues from non-firm energy sales and FMC secondary sales. Idaho Power's proposed PCA allows it to double recover fuel costs associated with load growth which, essentially, offsets the cost of constructing additional plant. We recognize

> and support the Company's right to recover costs associated with prudent plant additions. Our decision to not allow a PCA mechanism to recover costs to offset legitimate plant costs caused by load growth in no way prevents the Company from recovering these costs in traditional ratemaking proceedings. A PCA is not intended to replace the prudency review process inherent in a general rate case. (Order No. 24806, pg. 20, Emphasis added).

The load growth adjustment has been made in every PCA true up calculation since the PCA was established. Staff's intent from the initial PCA case was to update the load growth adjustment multiplier to reflect the average marginal cost of power supply as part of each general rate case. So doing would continue to remove the variable power supply costs associated with load growth that accumulate in the PCA at the marginal cost of supplying power.

Q. Please discuss Staff's review of the power supply cost load growth issue the next time it came up.

A. The Company's next general rate case was Case No. IPC-E-94-5. In that case Staff used the difference in power supply costs from two different power supply model runs to determine the marginal cost of power supply. The only difference in the two power supply model runs was that the second run was designed to meet an incrementally larger load. From those results a marginal cost of power supply of 16.22 $/MWh was calculated. (Case No. IPC-E-03-13, Hessing Direct, pg. 21, line 7). This result was

sufficiently close to the 16.84 $/MWh already in use that Staff proposed no change in the marginal cost multiplier by entering no testimony concerning this issue. No other party proposed that the multiplier change. The case contained no testimony concerning the multiplier.

Q. The power supply cost associated with load growth was an issue in the Company's next general rate case. Please discuss the case in that context.

A. The Company's next general rate case was the IPC-E-03-13 Case filed nearly 10 years later. In that case the Company proposed to reduce the multiplier, that it called the Expense Adjustment Rate for Growth or EARG, to 13.98 or 7.30 $/MWh based on two different interpretations of the purpose of the adjustment. In that case Staff did not use its own calculation of the marginal cost of power supply but used the "Marginal Cost of Energy" from Idaho Power's response to Request No. 30 of the Idaho Irrigation Pumpers Association. The amount from the study was 27.01 $/MWh which became 29.41 $/MWh when 8.9% losses were included. Based on those results Staff proposed a 29.41 $/MWh marginal cost multiplier. (Case No. IPC-E-03-13, Hessing Direct, pg. 20, line 16)

The Commission did not decide the magnitude of the multiplier in that case but set the issue aside along with several other issues to be settled by the parties. In

the give and take of settlement negotiations the multiplier stayed at 16.84 $/MWh but was, by specific settlement language, to be reevaluated in the next general rate case. The settlement was accepted by the Commission.

Q. Please discuss the power supply cost of load growth issue that was part of the Company's most recent general rate case.

A. The Company's next general rate case was Case No. IPC-E-05-28. This entire case was settled and the settlement was accepted by the Commission. During settlement discussions the Staff and Company differed substantially on the magnitude of the PCA load growth adjustment multiplier. The settlement called for a separate proceeding to decide the issue. This is that proceeding.

Q. Are Idaho's other regulated electric utilities allowed to track and defer differences between normal and actual power supply costs associated with load growth that occur between general rate cases for later recovery?

A. Rocky Mountain Power has no PCA and no tracking mechanism that allows it to track and recover these costs between rate cases. Avista Utilities has a PCA that is very similar to Idaho Power's. Its purpose is to track hydro conditions as they affect power supply costs. By Commission, Order Avista removes power supply costs

associated with load growth that occur between rate cases by multiplying load growth by the marginal cost of power supply and subtracting that amount from actual power supply costs. In Case No. AVU-E-04-1 the Commission established the load growth adjustment multiplier as 36.38 $/MWh. (Order No. 29602, pg. 46)

Q. Do you believe that Idaho Power Company should be allowed to recover the power supply costs of load growth through the PCA mechanism between rate cases?

A. No, I do not. Staff's position is the same as it was in the initial PCA case previously discussed in this testimony. It is also clear that the Commission ordered PCA that went into effect in 1993 was very specifically designed to remove the power supply costs of load growth.

Q. Was the Company required to absorb the power supply costs of load growth between rate cases prior to PCA approval?

A. Yes. The Commission's decision to remove load growth costs leaves the Company in the same position that it was in prior to the PCA. The Company receives revenue from sales of the growing load and has costs associated with serving the new load. If costs are more than revenues the Company can do what it has always done, make a rate filing to recover the difference prospectively.

Q. Do any other costs, established during a rate

case using a historic test year, vary in between rate cases?

A. Yes. Cost differences occur in virtually hundreds of utility accounts and must be trued up in a general rate case unless special treatment is approved by the Commission.

Q. Is there another reason that you oppose recovering the costs of load growth between rate cases?

A. Yes. It does not always follow that the costs of serving new load exceed the revenues derived from supplying new load. Generation and transmission investments are made in large increments. A single generation or transmission project may supply tens of thousands of new customers. This means that some of the costs that may be included in base rates are not incurred when load grows yet the Company receives revenue from the application of existing rates that may more than cover these embedded costs.

Q. Is there a long-standing reason why the actual costs associated with individual accounts or groups of accounts are not simply tracked through with annual rate adjustments between general rate cases?

A. Yes. In any given year the costs associated with some accounts may increase while the costs associated with other accounts may decrease. It is not fair or

reasonable to exclusively select one group of costs or the other. The only fair way to establish rates is to look at all the utilities costs together as is done in a general rate case.

Q. Is there another difference between the variable power supply costs associated with load growth and the variable power supply cost associated with fluctuating water conditions?

A. Yes. Load growth related power supply costs are addressed in a general rate case but power supply costs associated with abnormal water conditions are not. In a general rate case abnormal water conditions and their associted costs are normalized out.

Q. Do you have another concern with allowing the Company to recover the variable cost of power supply associated with load growth between rate cases?

A. Yes. This concern pits demand side management (DSM) programs against the two very different revenue streams that the Company could realize depending on the Commission's decision in this case. I would submit that the Company's incentive to grow load, or the disincentive for effective demand side management, is greatly increased when the Company receives the retail revenue from increased load and PCA reimbursement for power supply costs on the margin as opposed to just the retail revenue. In the first

case, for example, the Company could receive 84 $/MWh (8.4 ¢/kWh) for growing load. This could occur if retail revenue were 55 $/MWh and the marginal cost of power supply were 41 $/MWh which becomes 29 $/MWh when it is jurisdictionally allocated and shared before becoming a PCA rate ((41-6.81)*.941*.90=29). This scenario assumes that the Commission's decision in this case allows the Company to recover load growth power supply costs on the margin between rate cases. If the Commission does not allow this recovery then the Company receives only the retail revenue of 55 $/MWh. The incentive for growing load, not implementing effective DSM, is substantial if the Company receives 84 $/MWh in revenues from load growth.

Q. Does the Company currently have another filing before the Commission that is intended to remove the DSM disincentive that you have just described?

A. The Company does currently have another filing before the Commission, Case No. IPC-E-04-15, aimed at removing DSM disincentives, but it does not address the DSM disincentive that would be created in this case by the Company's proposal. In fact, because this other filing looks at use per customer, it is quite possible for PCA load to grow and use per customer to decline in which case the Company would receive additional revenues between rate cases from both adjustment mechanisms.

Q. What are the rate choices that the Commission could make for the load growth multiplier?

A. If the Commission decides to allow the Company to recover the variable cost of power supply associated with load growth between rate cases, then only the embedded variable cost of power supply should be subtracted from actual power supply costs in the PCA mechanism. This is what the Company proposes to do with its 6.81 $/MWh multiplier. The application of this multiplier prevents the double counting of embedded power supply costs.

If it is the Commission's decision to not allow the Company to recover the variable power supply costs associated with load growth through the PCA between general rate cases, then the adjustment should be made using the variable cost of power supply on the margin. Staff's most recent calculation of this amount is 40.87 $/MWh. The application of this multiplier prevents the double counting of embedded power supply costs and also prevents the PCA recovery of the power supply costs associated with load growth between rate cases. The calculation of this number is shown on Staff Exhibit No. 102. The number comes from two power supply model runs that differ by an increment of load. The base run is the model run presented by the Company in its most recent general rate case, Case No. IPC-E-05-28.

Q. Do the Company's proposed number and the Staff's proposed number come from the same power supply model?

A. Yes. Both numbers come from the Company's Aurora power supply model.

Q. Have you prepared an Exhibit that estimates the impacts of the various load growth adjustment multipliers?

A. Yes I have. Staff Exhibit No. 103 shows estimated annual load growth adjustments assuming a 40 MWa growth in load. Column (3) shows the annual adjustment at the current load growth adjustment rate of 16.84 $/MWh to be $5.9 million per year, Column (4) shows the adjustment at the Company proposed rate of 6.81 $/MWh to be $2.4 million per year and Column (5) shows the amount of the adjustment at the Staff proposed rate of 40.87 $/MWh to be $14.3 million per year. This load growth adjustment amount is cumulative between general rate cases until the base load is reestablished. For example, under Staff's proposal, the adjustment is estimated to be $28.6 million if the Company goes two years between general rate cases. Because these amounts can get quite large in a very few years, especially if Staff's load growth adjustment rate is accepted, this could be a significant factor affecting the frequency of Company rate case filings.

Q. A portion of the PCA rate that the Commission puts in place each year comes from the PCA forecast. How is the PCA forecast affected by the Company's proposal?

A. The Company is not proposing to change the forecast. Therefore, stream flow runoff forecasts would continue to be used to predict variations from normal power supply costs that would be expected under the normalized load. The problem is that under the Company's proposal the true up portion of the PCA is not tracking power supply costs under normalized load conditions but power supply costs under actual load conditions which includes the power supply costs associated with load growth that accumulate at the marginal cost of power supply. The result is that when load grows normal water conditions produce an increase in PCA rates and, good water conditions that should produce PCA rate reductions, could actually produce rate increases. This occurs because the true up mechanism is capturing costs associated with load growth rather than water conditions. The problem grows with time between general rate cases because load growth costs accumulate from year to year as previously discussed. Under the Company's proposal the PCA forecast based on water conditions would never be accurate and the customer price signal value of the forecast is significantly reduced if not completely lost.

Q. Does the Staff's position establish a bright line that identifies the purpose of the PCA?

A. Yes it does. It establishes the primary purpose of the PCA as a mechanism that tracks abnormal power supply costs primarily associated with variations in water conditions and market prices for a Commission approved normalized fixed load.

Q. What is the situation if the Company's position is accepted by the Commission?

A. Acceptance of the Company's position establishes a precedent for the recovery of costs between rate cases that could otherwise be captured in a general rate case and addressed with all other costs.

Q. Does this conclude your direct testimony in this proceeding?

A. Yes, it does.

TRUE-UP CALCULATIONS FOR 2005 - 2006
FOR
IDAHO POWER COMPANY PCA
CASE NO. IPC-E-06-07
Commission Decision

	DESCRIPTION	Units	2005 APR	2005 MAY	2005 JUN	2005 JUL	2005 AUG	2005 SEPT	2005 OCT
1									
2									
3	**PCA Revenue**								
4	Normalized Idaho Jurisd. Sales	MWh	862,931	881,064	1,002,040	1,185,074	1,303,702	1,164,116	925,105
5	Forecast Rate	m/KWh	2.499	2.499	4.288	4.288	4.288	4.288	4.288
6	Revenue	$	2,156,465	2,201,779	4,296,748	5,081,597	5,590,274	4,991,729	3,966,850
7									
8	**Load Change Adjustment**								
9	Actual System Firm Load - Adjusted	MWh	1,002,528	1,020,216	1,272,295	1,641,692	1,538,801	1,190,787	1,051,573
10	Normalized Firm Load	MWh	974,066	1,142,316	1,258,858	1,491,793	1,424,633	1,179,173	1,055,943
11	Load Change	MWh	28,462	(122,100)	13,437	149,899	114,168	11,614	(4,370)
12	Expense Adjustment (@16.84)	$	(479,300)	2,056,164	(226,279)	(2,524,299)	(1,922,589)	(195,580)	73,591
13									
14	**Non-QF PCA**								
15	ACTUAL:								
16	BPA Water Option Agreement	$	0	0	0	0	0	0	0
17	Cloud Seeding Program	$	57,788	256,201	0	0	0	0	0
18	Fuel Expense - Coal	$	6,527,289	7,516,168	8,878,317	9,168,717	8,963,765	9,093,240	8,374,911
19	Fuel Expense - Danskin	$	0	114,958	114,108	191,888	90,274	(639,672)	285,872
20	Fuel Expense - Bennett Mountain	$	333,725	169,001	654,700	1,480,609	450,682	(875,540)	6,783
21	Non-Firm Purchases	$	6,098,341	7,500,338	11,234,832	24,198,870	24,146,513	14,710,413	7,477,280
22	Surplus Sales	$	(5,434,762)	(18,370,968)	(14,206,066)	(11,376,337)	(9,360,602)	(12,538,689)	(13,902,800)
23	Expense Adjustment (@16.84)	$	(479,300)	2,056,164	(226,279)	(2,524,299)	(1,922,589)	(195,580)	73,591
24	Sub-Total	$	7,103,080	(758,138)	6,449,612	21,139,448	22,368,042	9,554,171	2,315,636
25									
26	BASE:								
27	Fuel Expense - Coal	$	7,108,200	6,800,600	6,344,900	8,714,800	8,721,300	8,446,500	8,727,700
28	Fuel Expense - Danskin	$	264,800	278,500	275,700	279,600	280,000	264,800	272,300
29	Fuel Expense - Bennett Mountain	$	0	0	0	0	0	0	0
30	Non-Firm Purchases	$	28,000	664,100	2,931,000	3,335,100	2,842,900	480,800	35,700
31	Surplus Sales	$	(9,187,500)	(6,566,900)	(4,558,900)	(2,385,400)	(3,371,000)	(5,702,300)	(4,982,500)
32	Surplus Sales Adder	$	0	0	0	0	0	0	0
33	Sub-Total	$	(1,786,500)	1,176,300	4,992,700	9,944,100	8,473,200	3,489,800	4,053,200
34									
35	Change From Base	$	8,889,580	(1,934,438)	1,456,912	11,195,348	13,894,842	6,064,371	(1,737,564)
36	Deferral (Shared and Allocated)	$	7,528,585	(1,638,276)	1,233,859	9,481,340	11,767,542	5,135,916	(1,471,543)
37									
38	**QF Deferral**								
39	Actual (includes Net Metering)	$	2,131,025	3,605,364	6,359,151	6,810,850	6,490,347	5,038,841	3,068,572
40	Base	$	2,815,766	4,160,399	6,508,847	6,702,897	6,422,258	5,081,395	3,792,830
41									
42	Change From Base	$	(684,741)	(555,035)	(149,696)	107,953	68,089	(42,554)	(724,258)
43	Deferral (Allocated)	$	(644,341)	(522,288)	(140,864)	101,584	64,071	(40,043)	(681,526)
44									
45	Intervenor Funding	$	0	0	0	0	0	0	0
46	Credit From IDACORP Energy	$	(166,667)	(166,667)	(166,667)	(166,667)	(166,667)	(166,667)	(166,667)
47	Settlement Agreement (ON 29600)	$	(804,167)	(804,167)	(804,167)	(804,167)	(804,167)	(804,167)	(804,167)
48	Bennett Mtn. Credit (ON 29790)	$	0	0	(3,986)	(3,986)	(3,986)	(3,986)	(3,986)
49	**Total Deferral** (-6+36+43+45+46+47+48)	$	3,756,946	(5,333,176)	(4,178,571)	3,526,508	5,266,520	(870,676)	(7,094,739)
50									
51	**Principal Balances**								
52	Beginning Balance	$	0	3,756,946	(1,576,230)	(5,754,801)	(2,228,293)	3,038,227	2,167,551
53	Amount Deferred	$	3,756,946	(5,333,176)	(4,178,571)	3,526,508	5,266,520	(870,676)	(7,094,739)
54	Ending Balance	$	3,756,946	(1,576,230)	(5,754,801)	(2,228,293)	3,038,227	2,167,551	(4,927,189)
55									
56	**Interest Balances**								
57	Accrual thru Prior Month	$	0	56	6,287	3,660	(5,935)	(9,504)	(4,545)
58	Interest @ 2% per Year	$	0	6,262	(2,627)	(9,591)	(3,714)	5,064	3,613
59	Prior Month's Interest Adj.	$	56	(31)	0	(4)	145	(105)	(10)
60	Total Current Month Interest	$	56	6,231	(2,627)	(9,595)	(3,569)	4,959	3,603
61	Interest Accrued to Date	$	56	6,287	3,660	(5,935)	(9,504)	(4,545)	(943)
62	**Balance (True-Up & Interest)**	$	3,757,003	(1,569,943)	(5,751,141)	(2,234,228)	3,028,722	2,163,005	(4,928,131)
63									
64	**True-Up of the True-Up**								
65	True-Up Revenues								
66	True Up Rates	¢/kWh	0.3707	0.3707	0.4024	0.4024	0.4024	0.4024	0.4024
67	Actual Idaho Sales	kWh	840,704,656	939,127,871	1,054,848,703	1,325,929,728	1,309,551,663	1,137,579,165	975,839,218
68	Total	$	3,164,039	3,002,187	2,701,380	2,176,780	2,406,699	2,173,844	1,723,273
69									
70	Beginning Balance	$	36,921,564	33,568,138	44,081,500	41,453,589	39,345,898	37,004,775	34,892,606
71	Adjustments per ON 29793								
72	Fuel Expense Adjustment	$	(250,506)	0	0	0	0	0	0
73	Intervenor Funding	$	0	(45,675)	0	0	0	0	0
74	Irrigation Lost Revenues ON 29669	$	0	13,482,882	0	0	0	0	0
75	Sub-Total	$	36,671,058	47,005,345	44,081,500	41,453,589	39,345,898	37,004,775	34,892,606
76	Interest @ 2% per Year	$	61,118	78,342	73,469	69,089	65,576	61,675	58,154
77	Revenue Applied to Interest	$	61,118	78,342	73,469	69,089	65,576	61,675	58,154
78	Revenue Applied to Balance	$	3,102,921	2,923,845	2,627,910	2,107,691	2,341,123	2,112,169	1,665,118
79	**True-Up of the True-Up Balance**	$	33,568,138	44,081,500	41,453,589	39,345,898	37,004,775	34,892,606	33,227,488
80									
81	Note: Negative amounts indicate benefit to ratepayers								

Exhibit No. 101
Case No. IPC-E-06-8
K. Hessing, Staff
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TRUE-UP CALCULATIONS FOR 2005 - 2006
FOR
IDAHO POWER COMPANY PCA
CASE NO. IPC-E-06-07
Commission Decision

	DESCRIPTION	Units	2005 NOV	2005 DEC	2006 JAN	2006 FEB	2006 MAR	TOTALS
1								
3	**PCA Revenue**							
4	Normalized Idaho Jurisd. Sales	MWh	885,609	965,920	1,043,993	968,236	909,048	12,096,838
5	Forecast Rate	m/KWh	4.288	4.288	4.288	4.288	4.288	
6	Revenue	$	3,797,491	4,141,865	4,476,642	4,151,796	3,897,998	48,751,234
7								
8	**Load Change Adjustment**							
9	Actual System Firm Load - Adjusted	MWh	1,137,344	1,354,735	1,244,146	1,124,755	1,139,815	14,718,687
10	Normalized Firm Load	MWh	1,079,817	1,220,489	1,207,127	1,032,883	1,040,475	14,107,573
11	Load Change	MWh	57,527	134,246	37,019	91,872	99,340	611,114
12	Expense Adjustment (@16.84)	$	(968,755)	(2,260,703)	(623,400)	(1,547,124)	(1,672,886)	(10,291,160)
13								
14	**Non-QF PCA**							
15	ACTUAL:							
16	BPA Water Option Agreement	$	0	0	0	0	0	0
17	Cloud Seeding Program	$	0	414,022	140,182	137,597	102,305	1,108,094
18	Fuel Expense - Coal	$	7,798,142	7,902,700	9,468,720	8,178,162	8,762,059	100,632,189
19	Fuel Expense - Danskin	$	377,898	314,726	24,885	88,089	29,016	992,041
20	Fuel Expense - Bennett Mountain	$	759	523,632	44,790	480	205,921	2,995,540
21	Non-Firm Purchases	$	12,196,111	32,754,148	22,190,694	13,292,649	12,443,565	188,243,754
22	Surplus Sales	$	(7,728,267)	(15,037,170)	(33,421,590)	(32,412,950)	(37,458,046)	(211,248,247)
23	Expense Adjustment (@16.84)	$	(968,755)	(2,260,703)	(623,400)	(1,547,124)	(1,672,886)	(10,291,160)
24	Sub-Total	$	11,675,887	24,611,354	(2,175,719)	(12,263,097)	(17,588,065)	72,432,211
25								
26	BASE:							
27	Fuel Expense - Coal	$	8,445,200	8,727,000	8,460,000	7,371,000	7,282,200	95,149,400
28	Fuel Expense - Danskin	$	264,700	272,800	272,500	257,500	273,400	3,256,600
29	Fuel Expense - Bennett Mountain	$	0	0	0	0	0	0
30	Non-Firm Purchases	$	610,900	884,100	397,900	88,700	77,700	12,376,900
31	Surplus Sales	$	(1,414,700)	(3,357,300)	(5,811,600)	(7,681,800)	(8,074,900)	(63,094,800)
32	Surplus Sales Adder	$	0	0	0	0	0	0
33	Sub-Total	$	7,906,100	6,526,600	3,318,800	35,400	(441,600)	47,688,100
34								
35	Change From Base	$	3,769,787	18,084,754	(5,494,519)	(12,298,497)	(17,146,465)	24,744,111
36	Deferral (Shared and Allocated)	$	3,192,633	15,315,978	(4,653,308)	(10,415,597)	(14,521,342)	20,955,787
37								
38	**QF Deferral**							
39	Actual (includes Net Metering)	$	2,095,280	2,315,598	2,792,655	2,707,472	2,497,723	45,912,878
40	Base	$	2,204,739	2,193,531	2,164,012	2,073,610	2,292,773	46,413,057
41								
42	Change From Base	$	(109,459)	122,067	628,643	633,862	204,950	(500,179)
43	Deferral (Allocated)	$	(103,001)	114,865	591,553	596,464	192,858	(470,669)
44								
45	Intervenor Funding	$	0	0	0	0	0	0
46	Credit From IDACORP Energy	$	(166,667)	(166,666)	0	0	0	(1,500,000)
47	Settlement Agreement (ON 29600)	$	(804,167)	(804,167)	(804,167)	(804,167)	(804,167)	(9,650,000)
48	Bennett Mtn. Credit (ON 29790)	$	(3,986)	(3,986)	(3,986)	(3,986)	(3,986)	(39,858)
49	**Total Deferral** (-6+36+43+45+46+47+48)	$	(1,682,679)	10,314,159	(9,346,550)	(14,779,081)	(19,034,634)	(39,455,973)
50								
51	**Principal Balances**							
52	Beginning Balance	$	(4,927,189)	(6,609,867)	3,704,291	(5,642,258)	(20,421,340)	
53	Amount Deferred	$	(1,682,679)	10,314,159	(9,346,550)	(14,779,081)	(19,034,634)	(39,455,973)
54	Ending Balance	$	(6,609,867)	3,704,291	(5,642,258)	(20,421,340)	(39,455,973)	
55								
56	**Interest Balances**							
57	Accrual thru Prior Month	$	(943)	(9,155)	(20,191)	(14,016)	(23,419)	
58	Interest @ 2% per Year	$	(8,212)	(11,016)	6,174	(9,404)	(34,036)	(57,488)
59	Prior Month's Interest Adj.	$	0	(20)	1	1	(276)	(242)
60	Total Current Month Interest	$	(8,212)	(11,036)	6,175	(9,403)	(34,312)	(57,730)
61	Interest Accrued to Date	$	(9,155)	(20,191)	(14,016)	(23,419)	(57,730)	
62	**Balance (True-Up & Interest)**	$	(6,619,022)	3,684,100	(5,656,274)	(20,444,758)	(39,513,704)	**(39,513,704)**
63								
64	**True-Up of the True-Up**							
65	True-Up Revenues							
66	True Up Rates	¢/kWh	0.4024	0.4024	0.4024	0.4024	0.4024	
67	Actual Idaho Sales	kWh	890,496,444	1,005,408,010	1,078,920,738	1,016,643,093	954,795,701	12,529,844,990
68	Total	$	1,568,690	1,889,864	1,988,372	1,739,243	1,776,360	26,310,731
69								
70	Beginning Balance	$	33,227,488	31,714,178	29,877,170	27,938,593	26,245,915	416,271,416
71	Adjustments per ON 29793							
72	Fuel Expense Adjustment	$	0	0	0	0	0	(250,506)
73	Intervenor Funding	$	0	0	0	0	0	(45,675)
74	Irrigation Lost Revenues ON 29669	$	0	0	0	0	0	13,482,882
75	Sub-Total	$	33,227,488	31,714,178	29,877,170	27,938,593	26,245,915	429,458,117
76	Interest @ 2% per Year	$	55,379	52,857	49,795	46,564	43,743	
77	Revenue Applied to Interest	$	55,379	52,857	49,795	46,564	43,743	715,764
78	Revenue Applied to Balance	$	1,513,310	1,837,007	1,938,577	1,692,679	1,732,617	25,594,967
79	**True-Up of the True-Up Balance**	$	31,714,178	29,877,170	27,938,593	26,245,915	24,513,298	**24,513,298**
80								
81	Note: Negative amounts indicate benefit to ratepayers							

Exhibit No. 101
Case No. IPC-E-06-8
K. Hessing, Staff
9/14/06 Page 2 of 2

IDAHO POWER COMPANY
CASE NO. IPC-E-06-8
STAFF MARGINAL COST CALCULATION
IPC-E-05-28 AURORA POWER SUPPLY BASE

	Units	Annual
IPC-E-05-28 Energy	MWh	13,866,817.3
IPC-E-05-28 Cost	M$	51,975.2
IPC-E-05-28 +10 MWa Energy	MWh	13,954,391.0
IPC-E-05-28 +10 MWa Cost	M$	55,554.1
Energy Difference	MWh	87,573.7
Cost Diffeence	M$	3,578.9
Marginal Cost	$/MWh	**40.87**

Exhibit No. 102
Case No. IPC-E-06-8
K. Hessing, Staff
9/14/06

IDAHO POWER COMPANY
CASE NO. IPC-E-06-8
STAFF LOAD GROWTH ADJUSTMENT CALCULATIONS

(1)	(2)	(3)	(4)	(5)
Description	Units	Load Growth Adjustment @ 16.84	Load Growth Adjustment @ 6.81	Load Growth Adjustment @ 40.87
Load Growth Adjustment Rate	$/MWh	16.84	6.81	40.87
Load Growth Energy (40 MWa)	MWh	350,400	350,400	350,400
Load Growth Adjustment	$	5,900,736	2,386,224	14,320,848

Exhibit No. 103
Case No. IPC-E-06-8
K. Hessing, Staff
9/14/06

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 14TH DAY OF SEPTEMBER 2006, SERVED THE FOREGOING **DIRECT TESTIMONY OF KEITH HESSING,** IN CASE NO. IPC-E-06-8, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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IDAHO POWER COMPANY
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GREGORY W SAID
DIRECTOR, REVENUE REQUIREMENT
IDAHO POWER COMPANY
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