

McDowell & Rackner PC



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February 27, 2009

VIA ELECTRONIC FILING

PUC Filing Center
Public Utility Commission of Oregon
PO Box 2148
Salem, OR 97308-2148

Re: Docket No. UE 195

Enclosed for filing in the above-referenced docket are an original and five copies of Idaho Power Company's 2008 Annual Power Supply Expense True-Up and Direct Testimony and Exhibits of Courtney Waites.

A copy of this filing has been served on all parties to this proceeding as indicated on the attached certificate of service.

Very truly yours,

A handwritten signature in cursive script that reads "Wendy L. McIndoo".

Wendy L. McIndoo

cc: Service List

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CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document in UE 195 on the following named person(s) on the date indicated below by email and first-class mail addressed to said person(s) at his or her last-known address(es) indicated below.

Stephanie S. Andrus
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DATED: February 27, 2009.



Wendy McIndoo
Legal Assistant

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BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 195

In The Matter of the Application of IDAHO
POWER COMPANY for Authority to
Implement a Power Cost Adjustment
Mechanism for Electric Service to Customers
in the State of Oregon.

**2008 ANNUAL POWER SUPPLY
EXPENSE TRUE-UP**

In compliance with Order No. 08-238, Idaho Power Company ("Idaho Power" or "the Company") hereby files its 2008 Annual Power Supply Expense True-Up ("True-Up") which implements the power cost adjustment mechanism ("PCAM") by calculating the deviation between actual net power supply expenses ("NPSE") and those expenses recovered through the Combined Rate. Accordingly, Idaho Power requests that the Public Utility Commission of Oregon ("Commission") issue an Order: (1) confirming that the Company has correctly calculated the amount of the True-Up for later inclusion in rates and authorizing the Company to add the Annual Power Cost Adjustment ("PCA") amount to the Annual Power Supply Expense True-Up Balancing Account ("True-Up Balancing Account"); and (2) authorizing the Company to delay amortization of the True-Up Balancing Account until it completes the amortization of previously authorized deferrals. This filing is based upon the following:

1. In Order No. 08-238 the Commission approved a PCAM for Idaho Power that requires the Company to file, in February of each year, a True-Up that will implement the PCAM by calculating the deviation between actual NPSE and those expenses recovered through the Combined Rate. Order No. 08-238 further requires that eligible power supply expense deviations will be added to the True-Up Balancing Account at the end of each 12 month period ending in December along with 50

1 percent of the annual interest calculated at the Company's authorized cost of capital.
2 The details of the required calculations are detailed in the Stipulation attached as
3 Exhibit A to Order No. 08-238.

4 2. As described in the Testimony of Courtney Waites, filed herewith, Idaho Power has
5 calculated its True-Up in accordance with the methodology approved by the
6 Commission in Order No. 08-238. Because Idaho Power cannot begin amortization
7 of the amount in the True-Up Balancing Account, the True-Up rate is 0.0000¢ per
8 kWh.

9 3. Order No. 08-238 provides that PCA amounts cannot be added to the True-Up
10 Balancing Account if the Company's earnings are within 100 basis points of the
11 Company's allowed ROE. If the Company's current earnings are more than 100
12 basis points below its allowed ROE, as measured from an Oregon Report of
13 Operations for the twelve months ended December 31 of the previous year, the
14 Company will be allowed to add the PCA amounts to the True-Up Balancing
15 Account, up to an earnings level that is 100 basis points less than the Company's
16 authorized ROE. Idaho Power confirms that its earnings as reported in the 2007
17 Oregon Report of Operations (filed May 6, 2008) are more than 100 basis points
18 below its allowed ROE and therefore the entire amount of the PCA may be added to
19 the True-Up Balancing Account.

20 4. OAR 860-027-0300(9)(a) provides that "[a]n energy utility shall request that
21 amortizations of deferred accounts commence no later than one year from the date
22 that the deferrals cease for that particular account." Because of the circumstances
23 described in the following paragraph, it is appropriate for the Commission to waive
24 application of OAR 860-027-0300(9)(a) with respect to the 2008 True-Up.

25 5. Idaho Power is currently amortizing excess power costs from 2001 authorized for
26 deferral in Order No. 01-307. Idaho Power began deferring these amounts in 2001

1 and anticipates that they will finally be fully amortized later this year. Since 2001, the
2 Commission has approved the Company's request to defer excess power costs for
3 2005-06¹, and 2006-07². In addition, the Company has filed for permission to defer
4 excess power costs for 2007-2008.³ Given the Company's relatively low revenues in
5 Oregon, coupled with the amortization cap included in ORS 757.259, it will be many
6 years before the Company can begin amortizing the 2008 True-Up Balancing
7 Account.

8
9 For all of the above reasons, Idaho Power requests that the Commission
10 issue its Order:

- 11 1. Confirming that the Company has correctly calculated the amount of the True-Up for
12 later inclusion in rates and authorizing the Company to add the PCA amount of
13 \$4,961,135.15 to the True-Up Balancing Account; and

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23 ¹ See Order No. 07-119 issued in UM 1007. The power cost deferral account for the 2005-06
year was entirely offset by SO2 allowances sold that year.

24 ² See Order No. 07-555 issued in UM 1198.

25 ³ See UM 1313. The Parties to this docket are in the process of memorializing a
Stipulation to allow Idaho Power to defer \$5,500,307.47 in excess power costs for 2007-
2008.

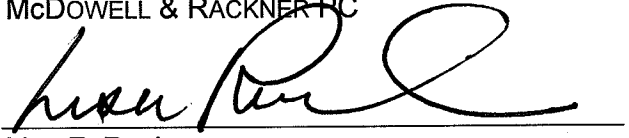
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1 2. Authorizing the Company to delay amortization of the 2008 True-Up Balancing
2 Account until it completes the amortization of previously authorized deferrals.

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4 Respectfully submitted this 27th day of February 2009.

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IDAHO POWER COMPANY

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 195

IN THE MATTER OF THE APPLICATION)
 OF IDAHO POWER COMPANY FOR)
 AUTHORITY TO IMPLEMENT A POWER)
 COST ADJUSTMENT TARIFF SCHEDULE)
 FOR ELECTRIC SERVICE TO CUSTOMERS)
 IN THE STATE OF OREGON.)
)
 ANNUAL POWER SUPPLY EXPENSE)
 TRUE-UP)
 _____)

IDAHO POWER COMPANY
 DIRECT TESTIMONY
 OF
 COURTNEY WAITES

1 **Q. Please state your name, business address and present**
2 **position with Idaho Power Company (the Company).**

3 A. My name is Courtney Waites. I am employed by Idaho Power
4 Company as a Pricing Analyst in the Pricing and Regulatory Services
5 Department. My business address is 1221 West Idaho Street, Boise, Idaho
6 83702.

7 **Q. Please describe your education background.**

8 A. In December of 1998, I received a Bachelor of Arts degree in
9 Accounting from the University of Alaska in Anchorage, Alaska. In 2000, I
10 earned a Master of Business Administration degree from Alaska Pacific
11 University. I have attended New Mexico State University's Center for Public
12 Utilities and the National Association of Regulatory Utility Commissioners
13 Practical Skills for the Changing Electric Industry conference and the Electric
14 Utility Consultants, Inc., Introduction to Rate Design and Cost of Service
15 Concepts and Techniques for Electric Utilities conference.

16 **Q. Please describe your work experience?**

17 A. I became employed with Idaho Power Company in December 2004
18 in the Accounts Payable Department. In 2005, I accepted a Regulatory
19 Accountant position in the Finance Department where one of my tasks was to
20 assist responding to regulatory data requests pertaining to the finance scope of
21 work. In 2006, I accepted my current position, a Pricing Analyst, in the Pricing
22 and Regulatory Services Department. My duties as a Pricing Analyst include
23 providing support for the Company's various regulatory activities including tariff

1 administration, regulatory ratemaking and compliance filings, and the
2 development of various pricing strategies and policies.

3 **Q. What is the purpose of your testimony?**

4 A. The purpose of my testimony is to describe the Company's Annual
5 Power Supply Expense True-up, which is required as detailed in Order No. 08-
6 238. This requires a determination of the dollar balance in the Annual Power
7 Supply Expense True-up Balancing Account.

8 **Q. What is the Annual Power Supply Expense True-up?**

9 A. The Annual Power Supply Expense True-up is a unit cost rate
10 calculated as the excess power supply expense or savings in the True-Up
11 Balancing Account, divided by the forecast of Normalized Sales for the upcoming
12 April through March period, divided by the Oregon Allocation factor. In February
13 of each year, the Company files the Annual Power Supply Expense True-Up
14 which will implement the Power Cost Adjustment Mechanism (Schedule 56).
15 This filing calculates the deviation between actual net power supply expenses
16 incurred for the preceding January through December period and the net power
17 supply expenses recovered through the Combined Rate for that same period.
18 For the purposes of the true-up, power cost are first calculated on a total system
19 basis and then allocated to Oregon based on the allocation factor.

20 **Q. What is the Annual Power Supply Expense True-up Balancing**
21 **Account?**

22 A. The Annual Power Supply Expense True-up Balancing Account
23 (True-up Balancing Account) is a Company account where the Power Cost

1 Adjustment (PCA) is added at the end of each 12-month period ending
2 December. Subject to an Earnings Test, the PCA is 90% of the amount that the
3 Oregon Allocated Power Cost Deviation is above or below the Power Supply
4 Expense Deadband.

5 **Q. What was the Oregon Allocated Power Cost Deviation, before**
6 **deadbands, for 2008?**

7 A. The Oregon Allocated Power Cost Deviation is the annual deviation
8 between the Combined Rate and the Actual Unit Cost times the Actual Sales,
9 multiplied by the current Oregon allocation factor. For 2008, the deviation
10 between the Combined Rate (\$7.57 per MWH) and the Actual Unit Cost (\$18.42
11 per MWH) is \$10.85 per MWH ($\$18.42 - \$7.57 = \10.85). This amount,
12 multiplied by the Actual Sales (14,543,712 MWh) equals the deviation from the
13 forecast, or \$157,789,697.63. Multiplying this amount by the Oregon allocation
14 factor of 4.72% results in an Oregon Allocated Power Cost Deviation, before
15 deadbands, of \$7,447,673.73.

16 **Q. How is the Actual Unit Cost calculated?**

17 A. The Actual Unit Cost for net power supply expenses incurred is the
18 total Actual Net Power Supply Expenses (Actual NPSE) incurred divided by the
19 Actual Sales. The Actual NPSE are determined on a system-wide basis and
20 include the amounts booked to FERC Accounts 501 (Fuel-Coal), 547 (Fuel-Gas),
21 555 (Purchased Power), and 447 (Sales for Resale). In short, Actual NPSE is
22 calculated by adding fuel plus purchased power less off system sales. The
23 Actual NPSE for 2008 was \$267,933,978.77. Actual Sales for 2008 was

1 14,543,712 MWh. Dividing Actual NPSE by Actual Sales results in the Actual
2 Unit Cost of \$18.42 per MWh ($\$267,933,978.77 \div 14,543,712 \text{ MWh} = \18.42
3 per MWh).

4 **Q. What is the Combined Rate?**

5 A. The Combined Rate is comprised of two components: the October
6 Power Cost Update and the March Power Cost Forecast. The Combined Rate in
7 effect from January through May, 2008 was \$3.47 per MWh and the Combined
8 Rate in effect from June through December, 2008 was \$10.22 per MWh. The
9 Combined Rate reflects the Commission approved amounts reflected in rates
10 during the months of the true-up period. The Annual Combined Rate, which is
11 weighted based on the five months of \$3.47 per MWh and the seven months of
12 \$10.22 per MWh, is \$7.57 per MWh.

13 **Q. What is the current Oregon allocation factor?**

14 A. The Oregon allocation factor is the energy allocator used in the
15 most recent Oregon Report of Operations. For the current PCAM period, the
16 2007 Oregon Report of Operations, filed with the Oregon Commission in May,
17 2008, has been used. The Oregon allocation factor is 4.72%.

18 **Q. Is the Oregon Allocated Power Cost Deviation, before**
19 **deadbands, of \$7,447,673.73, the amount of dollars to be added to the True-**
20 **up Balancing Account?**

21 A. No. Once the Oregon Allocated Power Cost Deviation is
22 calculated, a Power Supply Expense Deadband is applied.

1 **Q. Please explain how the Power Supply Expense Deadband is**
2 **applied.**

3 A. The Power Supply Expense Deadband (Deadband), which is based
4 upon the Company's authorized ROE from its last general rate case (10.00%)
5 and the rate base measured on an Oregon basis from the most recent Oregon
6 Results of Operations report (\$97,791,753), is applied to the Oregon Allocated
7 Power Cost Deviation. A positive deviation (Actual NPSE greater than those
8 recovered through the Combined Rate) constitutes an excess power supply
9 expense. This expense is first reduced by a deadband that is the dollar
10 equivalent of 250 basis points of ROE (Oregon basis). A negative deviation
11 (Actual NPSE less than those recovered through the Combined Rate) is a power
12 supply expense savings. This savings is reduced by a deadband that is the
13 dollar equivalent of 125 basis points of ROE (Oregon basis). Please see Exhibit
14 502 for a detail of this calculation.

15 **Q. What are the deadbands used for the calendar year 2008?**

16 A. Using the Company's authorized ROE of 10.00% and Oregon's rate
17 base of \$97,791,753, the Upper Band of 250 Basis Points equals \$2,005,569.99
18 and the Lower Band of 125 Basis Points equals a negative \$1,002,784.99

19 **Q. Once the deadbands are applied, what is the amount of the net**
20 **power supply expense deviation for the calendar year 2008?**

21 A. When the deadbands are applied to the Oregon Allocated Power
22 Cost Deviation, excess net power supply expenses of \$5,442,103.74 still exist.

1 Therefore, the 90% sharing factor is applied and the deferral amounts to a 2008
2 balance of \$4,897,893.36.

3 **Q. Once the deferral is calculated, an Earnings Test must be**
4 **applied. Please describe the application of the Earnings Test.**

5 A. Before any amounts of a deferral are approved for inclusion in the
6 Annual Power Supply Expense True-up Balancing Account for subsequent
7 recovery or refund, the Commission will apply an earnings test. If Idaho Power's
8 earnings are within plus or minus 100 basis points of its authorized ROE, as
9 measured from an Oregon Results of Operations report for the twelve months
10 ended December 31 of the previous year, excluding amounts that would be
11 added to the True-Up Balancing Account, no amounts will be added to the True-
12 up Balancing Account for that year. If the Company's current earnings are more
13 than 100 basis points below its authorized ROE (Oregon Basis), the Company
14 will be allowed to add the deferral to the True-Up Balancing Account, up to an
15 earnings level that is 100 basis points less than its authorized ROE. If the
16 Company's earnings are more than 100 basis points above its authorized ROE
17 (Oregon basis), it will be required to include the amount in the True-Up Balancing
18 Account as a credit, down to the authorized ROE plus 100 basis points threshold.

19 **Q. Has the Company performed the Earnings Test described**
20 **above?**

21 A. Yes. The Company has performed an Earnings Test (see Exhibit
22 503) based on the 2007 Oregon Results of Operations and has determined that
23 the Company's earnings are more than 100 basis points below its authorized

1 ROE (Oregon basis) and therefore concluded the deferral amount of
2 \$4,897,893.36 is eligible to be added to the Annual Power Supply Expense
3 True-Up Balancing Account.

4 **Q. You indicated the deferral amount proposed to be added to the**
5 **Annual Power Supply Expense True-Up Balancing Account is nearly \$4.9**
6 **million. What are some of the reasons for this deviation from forecasted**
7 **NPSE?**

8 A. The forecasted net power supply expenses on a total system basis
9 for the calendar year 2008 were \$87.0 million which was based on costs in both
10 the UE 167 and the UE 195 dockets. In UE 167, the Commission set Idaho
11 Power's net power supply expenses at negative \$1.8 million on a system-wide
12 basis. This was the basis for the deviation calculation until June 1, 2008 when
13 forecasted net power supply expenses changed as a result of docket UE 195.
14 Total actual net power supply expenses for 2008 were \$267.9 million, a
15 difference of \$180.9 million or more than 200% higher than forecasted. A
16 comparison of the forecasted net power supply expenses and the actual net
17 power supply expenses by account can be found in Exhibit 504.

18 Of the \$180.9 million deviation, \$103.1 million occurs in the first five
19 months of the year, when forecasted NPSE are based on net power supply
20 expenses set in Docket UE 167. During that period, the Company experienced
21 fuel costs \$16.6 million higher than forecasted, purchased power expenses \$64.1
22 million higher than forecasted, surplus sales \$22.6 million lower than forecasted

1 and energy sales 15% higher than expected, all driving the \$103.1 million
2 deviation.

3 For the remainder of 2008, the deviation from the forecasted NPSE
4 established in UE 195 was \$77.8 million. This deviation from forecasted NPSE
5 can largely be attributed to a delay in the start up of QF projects that were
6 expected to be online in 2008. Without these projects, the Company's purchased
7 power expenses increased while the actual surplus sales decreased.

8 **Q. What is another driver behind the higher than forecasted net**
9 **power supply expenses?**

10 A. Another primary driver of the deviation from forecasted net power
11 supply expenses was the Company's actual hydroelectric generation; in 2008 it
12 was 6.9 million MWh compared to a modeled median annual hydroelectric
13 generation of 8.5 million MWh based on hydrologic conditions for the period 1928
14 through 2006 and adjusted to reflect the current level of water resource
15 development. These extraordinarily low stream flow conditions cause the
16 Company to rely on other, higher cost sources of power.

17 **Q. Will any other amount be added to the Annual Power Supply**
18 **Expense True-Up Balancing Account?**

19 A. Yes. In addition to the deferral described above, the Company has
20 included fifty percent of the annual interest calculated at the Company's
21 authorized cost of capital in accordance with tariff Schedule 56, the Power Cost
22 Adjustment Mechanism, bringing the total amount to be added to the Annual
23 Power Supply Expense True-Up Balancing Account to \$5,089,645.89.

1 **Q. Does the Company propose any adjustments to this amount**
2 **before adding it to the True-up Balancing Account?**

3 A. Yes. The Company is also proposing to offset the deferral amount
4 in the Annual Power Supply Expense True-Up Balancing Account by the sale of
5 SO2 Allowances made during the calendar year 2008. As can be seen in Exhibit
6 505, the total customer benefit of sales made in 2008 is \$128,510.74, therefore
7 bringing the balance of the Annual Power Supply Expense True-Up Balancing
8 Account to \$4,961,135.15.

9 **Q. Based upon this addition to the Annual Power Supply Expense**
10 **True-up Balancing Account, what is the Annual Power Supply Expense**
11 **True-up for the upcoming April through March period?**

12 A. The Annual Power Supply Expense True-up rate for the April 2009
13 through March 2010 period is 0.0000¢ per kWh.

14 **Q. Why is the True-up Rate zero cents per kilowatt-hour?**

15 A. The Company currently has several excess net power supply
16 deferrals which will need to be fully amortized before the True-up Balance can
17 begin to be amortized. Once all of the prior deferral balances are fully amortized,
18 a True-up Rate to amortize the True-up Balance can be established.

19 **Q. Does this conclude your testimony?**

20 A. Yes it does.

Oregon PCAM Twelve Months Ended December 31, 2008

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	
OREGON PCAM (Schedule 56)		January	January YTD	February	February YTD	March	March YTD	April	April YTD	
ACTUAL POWER COSTS										
Actual NPSE Costs										
(1)	Actual Sales - Includes Unbilled	MWh	1,281,306	1,281,306	1,101,124	2,382,430	1,067,375	3,449,805	1,020,043	4,469,848
(2)	Fuel	\$	13,169,819.27	13,169,819.27	12,240,673.68	25,410,492.95	11,723,519.31	37,134,012.26	8,973,855.76	46,107,868.02
(3)	Purchased Power	\$	17,193,813.44	17,193,813.44	8,072,339.49	25,266,152.93	14,501,406.73	39,767,559.66	9,478,997.45	49,246,557.11
(4)	Surplus Sales	\$	(10,334,789.26)	(10,334,789.26)	(5,317,444.63)	(15,652,233.89)	(15,924,244.29)	(31,576,478.18)	(8,677,754.40)	(40,254,232.58)
(5)	Total Non-QF	\$	20,028,843.45	20,028,843.45	14,995,568.54	35,024,411.99	10,300,681.75	45,325,093.74	9,775,098.81	55,100,192.55
(6)	QF	\$	2,242,484.40	2,242,484.40	2,143,912.88	4,386,397.28	1,890,489.50	6,276,886.78	2,530,234.75	8,807,121.53
(7)	Total Actual Power Costs Incurred	\$	22,271,327.85	22,271,327.85	17,139,481.42	39,410,809.27	12,191,171.25	51,601,980.52	12,305,333.56	63,907,314.08
(8)	Actual Power Cost per Unit	\$/MWh	\$17.38	\$17.38	\$15.57	\$16.54	\$11.42	\$14.96	\$12.06	\$14.30
POWER COSTS COLLECTED IN RATES										
(9)	Actual Sales	MWh	1,281,306	1,281,306	1,101,124	2,382,430	1,067,375	3,449,805	1,020,043	4,469,848
(10)	Combined Rate (Recovered in Rates)	\$/MWh	\$3.47	\$3.47	\$3.47	\$3.47	\$3.47	\$3.47	\$3.47	\$3.47
(11)	Total Power Costs Collected in Rates	\$	4,446,131.82	4,446,131.82	3,820,900.28	8,267,032.10	3,703,791.25	11,970,823.35	3,539,549.21	15,510,372.56
CHANGE FROM FORECAST										
(12)	Actual Power Cost per Unit	\$/MWh	\$17.38	\$17.38	\$15.57	\$16.54	\$11.42	\$14.96	\$12.06	\$14.30
(13)	Combined Rate (Recovered in Rates)	\$/MWh	\$3.47	\$3.47	\$3.47	\$3.47	\$3.47	\$3.47	\$3.47	\$3.47
(14)	Actual Increase (Decrease) Over Forecast Rate	\$/MWh	\$13.91	\$13.91	\$12.10	\$13.07	\$7.95	\$11.49	\$8.59	\$10.83
(15)	Deviation from Forecast	\$	17,825,196.03	17,825,196.03	13,318,581.14	31,143,777.17	8,487,380.00	39,631,157.17	8,765,784.35	48,396,941.52
(16)	Oregon Allocation	%		4.72%		4.72%		4.72%		4.72%
(17)	Oregon Allocated Power Cost Deviation (before DB)	\$		841,349.25		1,469,986.28		1,870,590.62		2,284,335.64
(18)	Deadband - Over 250 Basis Points	\$		2,005,569.99		2,005,569.99		2,005,569.99		2,005,569.99
(19)	Deadband - Under 125 Basis Points	\$		(1,002,784.99)		(1,002,784.99)		(1,002,784.99)		(1,002,784.99)
(20)	True-Up (+)	\$		0.00		0.00		0.00		278,765.65
(21)	True-Up (-)	\$		0.00		0.00		0.00		0.00
(22)	OREGON DEFERRAL before sharing	\$		0.00		0.00		0.00		278,765.65
(23)	Portion of True-up Change Allowed	%		90%		90%		90%		90%
OREGON DEFERRAL w/ SHARING (90/10)		\$		0.00		0.00		0.00		250,889.09
(24)	Interest Rate	%		7.830%		7.830%		7.830%		7.830%
(25)	Interest Accrued to date	\$		0.00		0.00		0.00		3,274.10
(26)	Total Deferred Balance	\$		0.00		0.00		0.00		254,163.19

Oregon PCAM Twelve Months Ended December 31, 2008

		(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	
OREGON PCAM (Schedule 56)		May	May YTD	June	June YTD	July	July YTD	August	August YTD	
ACTUAL POWER COSTS										
Actual NPSE Costs										
(1)	Actual Sales - Includes Unbilled	MWh	1,232,738	5,702,586	1,358,252	7,060,838	1,638,020	8,698,858	1,450,588	10,149,446
(2)	Fuel	\$	8,875,459.94	54,983,327.96	10,491,551.01	65,474,878.97	14,227,121.14	79,702,000.11	17,614,602.08	97,316,602.19
(3)	Purchased Power	\$	16,331,781.93	65,578,339.04	10,211,045.93	75,789,384.97	26,082,335.55	101,871,720.52	22,785,141.80	124,656,862.32
(4)	Surplus Sales	\$	(8,438,165.49)	(48,692,398.07)	(5,257,208.28)	(53,949,606.35)	(8,082,568.49)	(62,032,174.84)	(9,669,473.07)	(71,701,647.91)
(5)	Total Non-QF	\$	16,769,076.38	71,869,268.93	15,445,388.66	87,314,657.59	32,226,888.20	119,541,545.79	30,730,270.81	150,271,816.60
(6)	QF	\$	4,538,615.73	13,345,737.26	6,651,507.27	19,997,244.53	7,424,814.15	27,422,058.68	6,605,859.00	34,027,917.68
(7)	Total Actual Power Costs Incurred	\$	21,307,692.11	85,215,006.19	22,096,895.93	107,311,902.12	39,651,702.35	146,963,604.47	37,336,129.81	184,299,734.28
(8)	Actual Power Cost per Unit	\$/MWh	\$17.28	\$14.94	\$16.27	\$15.20	\$24.21	\$16.89	\$25.74	\$18.16
POWER COSTS COLLECTED IN RATES										
(9)	Actual Sales	MWh	1,232,738	5,702,586	1,358,252	7,060,838	1,638,020	8,698,858	1,450,588	10,149,446
(10)	Combined Rate (Recovered in Rates)	\$/MWh	\$3.47	\$3.47	\$10.22	\$4.77	\$10.22	\$5.79	\$10.22	\$6.43
(11)	Total Power Costs Collected in Rates	\$	4,277,600.86	19,787,973.42	13,881,335.44	33,669,308.86	16,740,564.40	50,409,873.26	14,825,009.36	65,234,882.62
CHANGE FROM FORECAST										
(12)	Actual Power Cost per Unit	\$/MWh	\$17.28	\$14.94	\$16.27	\$15.20	\$24.21	\$16.89	\$25.74	\$18.16
(13)	Combined Rate (Recovered in Rates)	\$/MWh	\$3.47	\$3.47	\$10.22	\$4.77	\$10.22	\$5.79	\$10.22	\$6.43
(14)	Actual Increase (Decrease) Over Forecast Rate	\$/MWh	\$13.81	\$11.47	\$6.05	\$10.43	\$13.99	\$11.10	\$15.52	\$11.73
(15)	Deviation from Forecast	\$	17,030,091.25	65,427,032.77	8,215,560.49	73,642,593.26	22,911,137.95	96,553,731.21	22,511,120.45	119,064,851.66
(16)	Oregon Allocation	%		4.72%		4.72%		4.72%		4.72%
(17)	Oregon Allocated Power Cost Deviation (before DB)	\$		3,088,155.95		3,475,930.40		4,557,336.11		5,619,861.00
(18)	Deadband - Over 250 Basis Points	\$		2,005,569.99		2,005,569.99		2,005,569.99		2,005,569.99
(19)	Deadband - Under 125 Basis Points	\$		(1,002,784.99)		(1,002,784.99)		(1,002,784.99)		(1,002,784.99)
(20)	True-Up (+)	\$		1,082,585.96		1,470,360.41		2,551,766.12		3,614,291.01
(21)	True-Up (-)	\$		0.00		0.00		0.00		0.00
(22)	OREGON DEFERRAL before sharing	\$		1,082,585.96		1,470,360.41		2,551,766.12		3,614,291.01
(23)	Portion of True-up Change Allowed	%		90%		90%		90%		90%
OREGON DEFERRAL w/ SHARING (90/10)		\$		974,327.36		1,323,324.37		2,296,589.50		3,252,861.91
(24)	Interest Rate	%		7.830%		7.830%		7.830%		7.830%
(25)	Interest Accrued to date	\$		15,893.72		25,904.07		52,448.36		84,899.70
(26)	Total Deferred Balance	\$		990,221.08		1,349,228.45		2,349,037.86		3,337,761.60

Oregon PCAM Twelve Months Ended December 31, 2008

		(Q)	(R)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)
	OREGON PCAM (Schedule 56)	September	September YTD	October	October YTD	November	November YTD	December	December YTD	Annual
ACTUAL POWER COSTS										
(1)	Actual NPSE Costs									
	Actual Sales - Includes Unbilled	MWh	1,174,073	11,323,519	996,716	12,320,235	1,021,260	13,341,495	1,202,217	14,543,712
(2)	Fuel	\$	14,820,520.50	112,137,122.69	11,124,561.12	123,261,683.81	13,490,629.80	136,752,313.61	12,308,955.25	149,061,268.86
(3)	Purchased Power	\$	11,096,830.56	135,753,692.88	9,222,960.29	144,976,653.17	10,738,323.94	155,714,977.11	25,450,380.44	181,165,357.55
(4)	Surplus Sales	\$	(13,698,132.36)	(85,399,780.27)	(8,694,595.69)	(94,094,375.96)	(4,910,635.89)	(99,005,011.85)	(12,847,950.56)	(111,852,962.41)
(5)	Total Non-QF	\$	12,219,218.70	162,491,035.30	11,652,925.72	174,143,961.02	19,318,317.85	193,462,278.87	24,911,385.13	218,373,664.00
(6)	QF	\$	4,858,540.07	38,886,457.75	3,826,757.57	42,713,215.32	3,335,324.85	46,048,540.17	3,511,774.60	49,560,314.77
(7)	Total Actual Power Costs Incurred	\$	17,077,758.77	201,377,493.05	15,479,683.29	216,857,176.34	22,653,642.70	239,510,819.04	28,423,159.73	267,933,978.77
(8)	Actual Power Cost per Unit	\$/MWh	\$14.55	\$17.78	\$15.53	\$17.60	\$22.18	\$17.95	\$23.64	\$18.42
POWER COSTS COLLECTED IN RATES										
(9)	Actual Sales	MWh	1,174,073	11,323,519	996,716	12,320,235	1,021,260	13,341,495	1,202,217	14,543,712
(10)	Combined Rate (Recovered in Rates)	\$/MWh	\$10.22	\$6.82	\$10.22	\$7.10	\$10.22	\$7.33	\$10.22	\$7.57
(11)	Total Power Costs Collected in Rates	\$	11,999,026.06	77,233,908.68	10,186,437.52	87,420,346.20	10,437,277.20	97,857,623.40	12,286,657.74	110,144,281.14
CHANGE FROM FORECAST										
(12)	Actual Power Cost per Unit	\$/MWh	\$14.55	\$17.78	\$15.53	\$17.60	\$22.18	\$17.95	\$23.64	\$18.42
(13)	Combined Rate (Recovered in Rates)	\$/MWh	\$10.22	\$6.82	\$10.22	\$7.10	\$10.22	\$7.33	\$10.22	\$7.57
(14)	Actual Increase (Decrease) Over Forecast Rate	\$/MWh	\$4.33	\$10.96	\$5.31	\$10.51	\$11.96	\$10.62	\$13.42	\$10.85
(15)	Deviation from Forecast	\$	5,078,732.71	124,143,584.37	5,293,245.77	129,436,830.14	12,216,365.50	141,653,195.64	16,136,501.99	157,789,697.63
(16)	Oregon Allocation	%		4.72%		4.72%		4.72%		4.72%
(17)	Oregon Allocated Power Cost Deviation (before DB)	\$		5,859,577.18		6,109,418.38		6,686,030.83		7,447,673.73
(18)	Deadband - Over 250 Basis Points	\$		2,005,569.99		2,005,569.99		2,005,569.99		2,005,569.99
(19)	Deadband - Under 125 Basis Points	\$		(1,002,784.99)		(1,002,784.99)		(1,002,784.99)		(1,002,784.99)
(20)	True-Up (+)	\$		3,854,007.19		4,103,848.39		4,680,460.84		5,442,103.74
(21)	True-Up (-)	\$		0.00		0.00		0.00		0.00
(22)	OREGON DEFERRAL before sharing	\$		3,854,007.19		4,103,848.39		4,680,460.84		5,442,103.74
(23)	Portion of True-up Change Allowed	%		90%		90%		90%		90%
	OREGON DEFERRAL w/ SHARING (90/10)	\$		3,468,606.47		3,693,463.55		4,212,414.76		4,897,893.36
(24)	Interest Rate	%		7.830%		7.830%		7.830%		7.830%
(25)	Interest Accrued to date	\$		101,846.96		120,499.25		151,173.03		191,752.53
(26)	Total Deferred Balance	\$		3,570,453.43		3,813,962.80		4,363,587.79		5,089,645.89

**Determination of Oregon PCAM Deadbands
 Based on Idaho Power 2007 Report of Operations (Oregon Report)**

	(A)	(B)
	Total System	Oregon
(1) Rate Base	\$1,995,045,428	\$97,791,753
(2) % Equity in cap structure	49.960%	49.960%
(3) Equity in rate base	\$996,724,696	\$48,856,760
(4) 100 basis points	1.000%	1.000%
(5) Resulting return (NOI Effect)	\$9,967,247	\$488,568
(6) Net-to Gross Factor	1.64200	1.64200
(7) Revenue requirement	\$16,366,220	\$ 802,228
(8) Upper Band of Basis Points	250	\$2,005,569.99
(9) Lower Band of Basis Points	125	(\$1,002,784.99)

**IDAHO POWER COMPANY
 BEFORE THE OREGON PUBLIC UTILITY COMMISSION
 JURISDICTIONAL SEPARATION STUDY
 FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2007**

DESCRIPTION	TOTAL SYSTEM	OREGON OPUC
*** SUMMARY OF RESULTS ***		
DEVELOPMENT OF RATE BASE COMPONENTS		
1 ELECTRIC PLANT IN SERVICE	3,670,835,198	180,048,815
2 LESS: ACCUM PROVISION FOR DEPRECIATION	1,562,230,647	77,781,251
3 AMORT OF OTHER UTILITY PLANT	41,365,733	1,891,257
4 NET ELECTRIC PLANT IN SERVICE	2,067,238,818	100,376,307
5 LESS: CUSTOMER ADV FOR CONSTRUCTION	28,893,973	43,071
6 LESS: ACCUM DEFERRED INCOME TAXES	203,416,395	9,981,490
7 ADD : PLT HLD FOR FUTURE+ACQUIS ADJ	0	0
8 ADD : WORKING CAPITAL	80,358,755	3,945,874
9 ADD : CONSERVATION+OTHER DFRD PROG.	9,664,260	123,555
10 ADD : SUBSIDIARY RATE BASE	70,093,970	3,370,579
11		
12 TOTAL COMBINED RATE BASE	1,995,045,434	97,791,754
13		
14 RATE OF RETURN UNDER PRESENT RATES		
15 OPERATING REVENUES		
16 SALES REVENUES	794,341,213	34,320,315
17 OTHER OPERATING REVENUES	42,426,194	1,591,844
18 TOTAL OPERATING REVENUES	836,767,407	35,912,159
19 OPERATING EXPENSES		
20 OPERATION & MAINTENANCE EXPENSES	557,486,291	26,593,578
21 DEPRECIATION EXPENSE	98,483,944	4,822,074
22 AMORTIZATION OF LIMITED TERM PLANT	6,697,372	321,809
23 TAXES OTHER THAN INCOME	18,169,063	1,348,308
24 REGULATORY DEBITS/CREDITS	21,246	0
25 PROVISION FOR DEFERRED INCOME TAXES	-6,344,826	0
26 INVESTMENT TAX CREDIT ADJUSTMENT	1,978,842	0
27 FEDERAL INCOME TAXES	38,112,027	0
28 STATE INCOME TAXES	232,866	0
29 TOTAL OPERATING EXPENSES	714,836,825	33,085,770
30 OPERATING INCOME	121,930,582	2,826,389
31 ADD: IERCO OPERATING INCOME	4,862,780	233,834
32 CONSOLIDATED OPERATING INCOME	126,793,362	3,060,223
33		
34 RATE OF RETURN UNDER PRESENT RATES		3.129%

**IDAHO POWER COMPANY
 BEFORE THE OREGON PUBLIC UTILITY COMMISSION
 JURISDICTIONAL SEPARATION STUDY
 FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2007**

DESCRIPTION	TOTAL SYSTEM	OREGON OPUC
*** SUMMARY OF RESULTS ***		
RATE OF RETURN UNDER PRESENT RATES		
35 TOTAL COMBINED RATE BASE	1,995,045,434	97,791,754
36		
37 SALES REVENUES	794,341,213	34,320,315
38 OTHER OPERATING REVENUES	42,426,194	1,591,844
39 TOTAL OPERATING REVENUES	836,767,407	35,912,159
40 OPERATING EXPENSES		
41 OPERATION & MAINTENANCE EXPENSES	557,486,291	26,593,578
42 DEPRECIATION EXPENSE	98,483,944	4,822,074
43 AMORTIZATION OF LIMITED TERM PLANT	6,697,372	321,809
44 TAXES OTHER THAN INCOME	18,169,063	1,348,308
45 REGULATORY DEBITS/CREDITS	21,246	0
46 PROVISION FOR DEFERRED INCOME TAXES	-6,344,826	0
47 INVESTMENT TAX CREDIT ADJUSTMENT	1,978,842	0
48 FEDERAL INCOME TAXES	38,112,027	0
49 STATE INCOME TAXES	232,866	0
50 TOTAL OPERATING EXPENSES	714,836,825	33,085,770
51 OPERATING INCOME	121,930,582	2,826,389
52 ADD: IERCO OPERATING INCOME	4,862,780	233,834
53 CONSOLIDATED OPERATING INCOME	126,793,362	3,060,223
54 RATE OF RETURN UNDER PRESENT RATES		3.129%
55		
56 DEVELOPMENT OF REVENUE REQUIREMENTS		
57 RATE OF RETURN REQUIRED		7.830%
58		
59 RETURN AT CLAIMED RATE OF RETURN		7,657,094
60 EARNINGS DEFICIENCY		4,596,871
61 NET-TO-GROSS TAX MULTIPLIER		1.642
62		
63 REVENUE DEFICIENCY		7,548,062
64		
65 FIRM JURISDICTIONAL REVENUES		27,369,858
66		
67 PERCENT INCREASE REQUIRED		27.58%
68		
69 SALES AND WHEELING REVENUES REQUIRED		34,917,920

Monthly Net Power Supply Expenses

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	From UE 167					UE 195							
	January	February	March	April	May	June	July	August	September	October	November	December	Total
ANNUAL FORECAST													
Forecast NPSE Costs													
(1) Forecast Sales (MWh)	1,114,794	1,036,442	974,421	919,011	932,752	1,193,011	1,409,445	1,501,396	1,361,068	1,111,407	1,061,938	1,175,080	13,790,765
(2) Fuel	\$8,732,488.78	\$7,628,426.60	\$7,555,660.68	\$7,372,963.18	\$7,079,207.83	\$10,373,822.30	\$12,206,336.97	\$12,326,315.66	\$11,057,313.68	\$11,302,355.53	\$11,051,869.15	\$11,531,811.70	\$ 118,218,572.04
(3) Purchased Power	\$612,586.40	\$134,008.56	\$116,325.12	\$34,371.43	\$621,779.66	\$5,851,511.65	\$22,568,627.42	\$12,244,095.83	\$7,242,259.69	\$5,159,915.31	\$10,122,871.00	\$18,905,309.56	\$ 83,613,661.63
(4) Surplus Sales	\$13,096,549.45	\$18,473,726.01	\$18,003,055.59	\$12,906,668.55	\$8,805,176.75	\$19,661,992.26	\$36,386,171.65	\$17,068,309.38	\$23,097,230.85	\$6,724,890.23	\$9,816,772.20	\$6,999,308.56	\$ 191,039,851.77
(5) Total Non-QF	(\$3,751,474.28)	(\$10,711,290.85)	(\$10,331,069.80)	(\$5,499,333.95)	(\$1,104,189.27)	(\$3,436,658.31)	(\$1,611,207.26)	\$7,502,102.11	(\$4,797,657.48)	\$9,737,380.61	\$11,357,967.96	\$23,437,812.41	\$ 10,792,381.91
(6) QF	\$2,164,012.00	\$2,073,610.00	\$2,292,773.00	\$2,815,770.00	\$4,160,399.00	\$10,511,096.97	\$10,932,319.80	\$10,510,090.48	\$8,755,073.74	\$7,357,532.79	\$6,924,379.64	\$7,741,336.11	\$ 76,238,393.53
(7) Total Forecast Power Costs (\$)	(\$1,587,462.28)	(\$8,637,680.85)	(\$8,038,296.80)	(\$2,683,563.95)	\$3,056,209.73	\$7,074,438.66	\$9,321,112.54	\$18,012,192.59	\$3,957,416.27	\$17,094,913.40	\$18,282,347.60	\$31,179,148.52	\$ 87,030,775.44
(8) Combined Rate (Recovered in Rates)	\$3.47	\$3.47	\$3.47	\$3.47	\$3.47	\$10.22	\$10.22	\$10.22	\$10.22	\$10.22	\$10.22	\$10.22	\$10.22
ACTUAL POWER COSTS													
Actual NPSE Costs													
(9) Actual Sales (MWh)	1,281,306	1,101,124	1,067,375	1,020,043	1,232,738	1,358,252	1,638,020	1,450,588	1,174,073	996,716	1,021,260	1,202,217	14,543,712
(10) Fuel	\$ 13,169,819.27	\$ 12,240,673.68	\$ 11,723,519.31	\$ 8,973,855.76	\$ 8,875,459.94	\$ 10,491,551.01	\$ 14,227,121.14	\$ 17,614,602.08	\$ 14,820,520.50	\$ 11,124,561.12	\$ 13,490,629.80	\$ 12,308,955.25	\$ 149,061,268.86
(11) Purchased Power	17,193,813.44	8,072,339.49	14,501,406.73	9,478,997.45	16,331,781.93	10,211,045.93	26,082,335.55	22,785,141.80	11,096,830.56	9,222,960.29	10,738,323.94	25,450,380.44	\$ 181,165,357.55
(12) Surplus Sales	10,334,789.26	5,317,444.63	15,924,244.29	8,677,754.40	8,438,165.49	5,257,208.28	8,082,568.49	9,669,473.07	13,698,132.36	8,694,595.69	4,910,635.89	12,847,950.56	\$ 11,852,962.41
(13) Total Non-QF	\$ 20,028,843.45	\$ 14,995,568.54	\$ 10,300,681.75	\$ 9,775,098.81	\$ 16,769,076.38	\$ 15,445,388.66	\$ 32,226,888.20	\$ 30,730,270.81	\$ 12,219,218.70	\$ 11,652,925.72	\$ 19,318,317.85	\$ 24,911,385.13	\$ 218,373,664.00
(14) QF	2,242,484.40	2,143,912.88	1,890,489.50	2,530,234.75	4,538,615.73	6,651,507.27	7,424,814.15	6,605,859.00	4,858,540.07	3,826,757.57	3,335,324.85	3,511,774.60	\$ 49,560,314.77
(15) Total Actual Power Costs Incurred (\$)	\$ 22,271,327.65	\$ 17,139,481.42	\$ 12,191,171.25	\$ 12,305,333.56	\$ 21,307,692.11	\$ 22,096,895.93	\$ 39,651,702.35	\$ 37,336,129.81	\$ 17,077,758.77	\$ 15,479,683.29	\$ 22,653,642.70	\$ 28,423,159.73	\$ 267,933,978.77
(16) Actual Power Cost per Unit	\$ 17.38	\$ 15.57	\$ 11.42	\$ 12.06	\$ 17.28	\$ 16.27	\$ 24.21	\$ 25.74	\$ 14.55	\$ 15.53	\$ 22.18	\$ 23.64	\$ 18.42
DEVIATION													
Difference in NPSE Costs													
(17) Actual Sales vs. Forecast Sales (MWh)	166,512	64,682	92,954	101,032	299,986	165,241	228,575	(50,808)	(186,995)	(114,691)	(40,678)	27,137	752,947
(18) Fuel	\$ 4,437,330.49	\$ 4,612,247.08	\$ 4,167,858.63	\$ 1,600,892.58	\$ 1,796,252.11	\$ 117,728.71	\$ 2,020,784.17	\$ 5,288,286.42	\$ 3,763,206.82	\$ (177,794.41)	\$ 2,438,760.65	\$ 777,143.55	\$ 30,842,696.82
(19) Purchased Power	16,581,227.04	7,938,330.93	14,385,081.61	9,444,626.02	15,710,002.27	4,359,534.28	3,513,708.13	10,541,045.97	3,854,570.87	4,063,044.98	815,452.94	6,545,070.88	\$ 97,551,695.92
(20) Surplus Sales	(2,761,760.19)	(13,156,281.38)	(2,078,811.30)	(4,228,914.15)	(367,011.26)	(14,404,783.98)	(28,303,603.16)	(7,398,836.31)	(9,399,098.49)	1,969,705.46	(4,906,136.31)	5,848,641.71	\$ (79,186,889.36)
(21) Total Non-QF	\$ 23,780,317.73	\$ 25,706,859.39	\$ 20,631,751.55	\$ 15,274,432.76	\$ 17,873,265.65	\$ 18,882,046.97	\$ 33,838,095.46	\$ 23,228,168.70	\$ 17,016,876.18	\$ 1,915,545.11	\$ 7,960,349.89	\$ 1,473,572.72	\$ 207,581,282.09
(22) QF	78,472.40	70,302.88	(402,283.50)	(285,535.25)	378,216.73	(3,859,589.70)	(3,507,505.65)	(3,904,231.48)	(3,896,533.67)	(3,530,775.22)	(3,589,054.79)	(4,229,561.51)	\$ (26,678,078.76)
(23) Total Actual Power Costs Incurred (\$)	\$ 23,858,790.13	\$ 25,777,162.27	\$ 20,229,468.05	\$ 14,988,897.51	\$ 18,251,482.38	\$ 15,022,457.27	\$ 30,330,589.81	\$ 19,323,937.22	\$ 13,120,342.50	\$ (1,615,230.11)	\$ 4,371,295.10	\$ (2,755,988.79)	\$ 180,903,203.33

