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February 27, 2009

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Public Utility Commission of Oregon
Administrative Hearing Division

VIA ELECTRONIC FILING

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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,

Wendy McIndoo

Wendy L. McIndoo

cc: Service List

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
Department of Justice
Regulated Utility & Business Section
1162 Court St NE
Salem, OR 97301-4096
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Bob Jenks
Citizens' Utility Board of Oregon
bob@oregoncub.org

DATED: February 27, 2009.

Wendy McIndoo

Wendy McIndoo
Legal Assistant

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

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

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

Q. Please describe your education background.

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

Q. Please describe your work experience?

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

Q. What is the purpose of your testimony?

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

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

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

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

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

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

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

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

Q. How is the Actual Unit Cost calculated?

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

14,543,712 MWh. Dividing Actual NPSE by Actual Sales results in the Actual Unit Cost of $18.42 per MWH ($267,933,978.77 ÷ 14,543,712 MWh = $18.42 per MWH).

Q. What is the Combined Rate?

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

Q. What is the current Oregon allocation factor?

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

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

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

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

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

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

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

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

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

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

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

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

Q. Has the Company performed the Earnings Test described above?

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

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

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

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

Of the $180.9 million deviation, $103.1 million occurs in the first five months of the year, when forecasted NPSE are based on net power supply expenses set in Docket UE 167. During that period, the Company experienced fuel costs $16.6 million higher than forecasted, purchased power expenses $64.1 million higher than forecasted, surplus sales $22.6 million lower than forecasted and energy sales 15% higher than expected, all driving the $103.1 million deviation.

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

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

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

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

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

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

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

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

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

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

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

Q. Does this conclude your testimony?

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

	OREGON PCAM (Schedule 56)		(I) May	(J) May YTD	(K) June	(L) June YTD	(M) July	(N) July YTD	(O) August	(P) 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										
	Actual NPSE Costs										
(1)	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	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	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	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)	(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	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	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	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**	**$18.42**
	POWER COSTS COLLECTED IN RATES										
(9)	Actual Sales	MWh	1,174,073	11,323,519	996,716	12,320,235	1,021,260	13,341,495	1,202,217	14,543,712	14,543,712
(10)	**Combined Rate (Recovered in Rates)**	**$/MWh**	**$10.22**	**$6.82**	**$10.22**	**$7.10**	**$10.22**	**$7.33**	**$10.22**	**$7.57**	**$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	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	$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	$7.57
(14)	**Actual Increase (Decrease) Over Forecast Rate**	**$/MWh**	**$4.33**	**$10.96**	**$5.31**	**$10.51**	**$11.96**	**$10.62**	**$13.42**	**$10.85**	**$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	157,789,697.63
(16)	**Oregon Allocation**	**%**		**4.72%**		**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**	**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**	**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)**	**(1,002,784.99)**
(20)	True-Up (+)	$		3,854,007.19		4,103,848.39		4,680,460.84		5,442,103.74	5,442,103.74
(21)	True-Up (-)	$		0.00		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	5,442,103.74
(23)	Portion of True-up Change Allowed	%		90%		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**	**4,897,893.36**
(24)	Interest Rate	%		7.830%		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	191,752.53
(26)	**Total Deferred Balance**	**$**		**3,570,453.43**		**3,813,962.80**		**4,363,587.79**		**5,089,645.89**	**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
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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	$6,999,308.85	**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	
	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	**111,852,962.41**
(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 ($)	$ 22,271,327.85	$ 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	615,452.94	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**

Oregon Emission Sales
January 2008 thru December 2008

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
			2008												
			January	February	March	April	May	June	July	August	September	October	November	December	Totals
(1)	Prior Month Sale(s)	$	0.00	0.00	0.00	0.00	556,000.00	882,500.00	1,522,500.00	0.00	0.00	0.00	0.00	0.00	2,961,000.00
(2)	Brokerage Fee's Paid in Prior Month	$	0.00	0.00	0.00	0.00	(500.00)	(750.00)	(1,250.00)	0.00	0.00	0.00	0.00	0.00	(2,500.00)
(3)	Net Proceeds	$	0.00	0.00	0.00	0.00	555,500.00	881,750.00	1,521,250.00	0.00	0.00	0.00	0.00	0.00	2,958,500.00
(4)	Oregon Allocation		4.72%	4.72%	4.72%	4.72%	4.72%	4.72%	4.72%	4.72%	4.72%	4.72%	4.72%	4.72%	4.72%
(5)	Sharing Percentage		90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%
(6)	Total Customer Benefit	$	0.00	0.00	0.00	0.00	23,597.64	37,456.74	64,622.70	0.00	0.00	0.00	0.00	0.00	125,677.07
(7)	Less Taxes @	39.095%	0.00	0.00	0.00	0.00	(9,225.50)	(14,643.71)	(25,264.24)	0.00	0.00	0.00	0.00	0.00	(49,133.45)
(8)	Customer Benefit Net of Tax - Oregon	$	0.00	0.00	0.00	0.00	14,372.14	22,813.03	39,358.46	0.00	0.00	0.00	0.00	0.00	76,543.62
	Principle														
(9)	Beginning Balance	$	0.00	0.00	0.00	0.00	0.00	14,372.14	37,185.17	76,543.63	76,543.63	76,543.63	76,543.63	76,543.63	0.00
(10)	Amount Deferred		0.00	0.00	0.00	0.00	14,372.14	22,813.03	39,358.46	0.00	0.00	0.00	0.00	0.00	76,543.63
(11)	Ending Balance	$	0.00	0.00	0.00	0.00	14,372.14	37,185.17	76,543.63	76,543.63	76,543.63	76,543.63	76,543.63	76,543.63	76,543.63
	Interest														
(12)	Beginning Balance	$	0.00	0.00	0.00	0.00	0.00	0.00	93.78	336.41	835.86	1,335.31	1,834.76	2,334.21	0.00
(13)	Monthly Interest Rate		7.83%	7.83%	7.83%	7.83%	7.83%	7.83%	7.83%	7.83%	7.83%	7.83%	7.83%	7.83%	7.83%
(14)	Monthly Interest	$	0.00	0.00	0.00	0.00	0.00	93.78	242.63	499.45	499.45	499.45	499.45	499.45	2,833.66
(15)	Interest Accrued to Date	$	0.00	0.00	0.00	0.00	0.00	93.78	336.41	835.86	1,335.31	1,834.76	2,334.21	2,833.66	2,833.66
(0)	Deferral Balance Including Interest	$	0.00	0.00	0.00	0.00	14,372.14	37,278.95	76,880.04	77,379.49	77,878.94	78,378.39	78,877.84	79,377.29	79,377.29
(17)	Tax Benefit from Above	$													49,133.45
(18)	Total Customer Benefit	$													128,510.74