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August 17, 2007

VIA ELECTRONIC FILING

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

Re: Docket UE _____

Enclosed for filing is Idaho Power Company's Application for Authority to Implement a Power Cost Adjustment Mechanism for Electric Service to Customers in the State of Oregon, along with the Direct Testimony and Exhibits of Michael J. Youngblood and Gregory W. Said. A copy of this filing has been served on all parties to our previous rate case, UE 167.

Very truly yours,

Lisa F. Rackner

Enclosures
cc: UE 167 Service List

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CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document 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.

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DATED: August 17, 2007.

Lisa F. Rackner

Of Attorneys for Idaho Power Company

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE _____

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.	**APPLICATION AND WAIVER OF PAPER SERVICE**

I. INTRODUCTION

Pursuant to ORS 757.205 and 757.210, Idaho Power Company ("Idaho Power" or the "Company") respectfully requests that the Oregon Public Utility Commission (the "Commission") approve its proposed Power Cost Adjustment Mechanism ("PCAM") for the Company's Oregon jurisdiction. The proposed PCAM will match revenues from rates to the Company's actual net power costs, and constitutes an "automatic adjustment clause" as contemplated by ORS 757.210(1).

In the Idaho Power's last rate case, UE 167, the Commission recognized that the Company's system is uniquely reliant on hydro generation.[1] This fact subjects Idaho Power's power supply expenses to extreme variability,[2] the impact of which is asymmetric, causing the Company to incur excess power supply expenses more frequently than it benefits from lower costs.[3] As a result of these factors, recurring drought conditions over multiple years have resulted in power supply expenses significantly in excess of those included in rates and have forced the Company to file for (and receive) multiple excess

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[1] Order No. 05-871 at 7.

[2] *See* Direct Testimony of Gregory Said, filed herewith, Idaho Power/200, Said/5.

[3] In his testimony filed in UE 167, Company witness Gregory Said explained the asymmetric impact of hydro variability on the Company. *See* Idaho Power/200, Said/8, filed in that case.

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power supply expense deferrals.[4] Moreover, because Oregon law limits the amount of the deferral balances that may be included in rates,[5] Idaho Power's deferrals are subject to prolonged amortization periods. The result is a significant mismatch of costs and benefits, as the extraordinary costs incurred to serve customers during drought periods are shifted onto later generations of customers.

In UE 167, the Commission directed the parties to work together to consider alternative regulatory mechanisms that will more effectively allow Idaho Power to recover its allowable power costs.[6] Accordingly, the Company met with Commission Staff, Citizens' Utility Board of Oregon, and Oregon Industrial Customers of Idaho Power in order to share ideas regarding an appropriate mechanism. The Company makes this filing as the culmination of those discussions.

The PCAM described in this Application will closely align the power supply expenses included in customer rates with the power supply expenses actually incurred by the Company. In so doing, the PCAM will ensure that customers that use energy today are responsible for the costs that are incurred on their behalf, and further will allow current customers to benefit from lower rates when conditions drive actual power expenses below normalized rates. Moreover, Idaho Power's proposed PCAM reflects a fair and appropriate

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[4] In UM 1198, the Company filed an application for authorization to defer excess power supply expenses for 2005-06. That application was granted (Order No. 05-870) and the Commission subsequently approved $2,889,117 in Oregon jurisdictionally-allocated excess power supply expenses for amortization (Order No. 07-119).

In UM 1261, the Company filed an application for authorization to defer $3,254,778 in Oregon jurisdictionally-allocated excess power supply expenses for 2006-07. The parties have reached a Stipulation in that case.

In UM 1331, the Company filed an application for authorization to defer $5,705,230 in Oregon jurisdictionally-allocated excess power supply expenses for 2007-08. No action has been taken on that application.

[5] *See* ORS 757.259.

[6] Order No. 05-871 at 7.

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allocation of the risks and rewards associated with Idaho Power's hydro generation system. For all of these reasons, Idaho Power requests that the Commission grant this Application and adopt the Company's proposed PCAM.

II. NOTICE AND EXHIBITS

In accordance with OAR 860-013-0070, Idaho Power hereby waives service by means other than service by electronic mail. Consistent with that waiver, communications regarding this Application should be addressed to all of the following:

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In support of this Application, Idaho Power submits proposed Schedule 55, the tariff that would implement the PCAM, attached to this Application as Attachment A and the testimonies and exhibits of Company witnesses, Gregory W. Said and Michael J. Youngblood.

Idaho Power served copies of this Application and supporting documents on each of the parties in UE 167.

III. PROPOSED PCAM STRUCTURE

Idaho Power proposes a PCAM with three distinct components: (1) the Annual Base Rate Update (alternatively, "Annual Update"); (2) the Annual Forecast of Power Supply Expenses (alternatively, "Annual Forecast"); and (3) the Annual Power Supply Expense True Up (alternatively, "Annual True-Up"). As described in this Section, these three components will operate together to appropriately align Oregon customers' rates with their share of the actual net power supply expenses incurred by the Company.

A. Annual Base Rate Update

In October 2007 and each October thereafter, Idaho Power will file its best estimate of "normal" power supply expenses for the upcoming water year, April through March. This filing will be used to establish the prospective "base" power supply expense rate component associated with the forward test year period. The filed estimate will include forecasted "normal" loads, resources, market prices, fuel expenses, purchased power expenses and surplus sales revenues under normal stream flow conditions. After adding expenses associated with energy purchases from facilities qualified under the Public Utility Regulatory Policy Act of 1978 ("PURPA"), the total net power supply expense will be divided by the expected kilowatt-hour ("kWh") sales to calculate the updated unit cost per kWh. The updated current cost per kWh will replace the existing unit cost per kWh included in the Company's rates. The current base rate for power supply expense established in UE 167 is 0.316 cents per kWh. The Company anticipates that the annual base rate update will be implemented for the first time on June 1, 2008 and annually on each June 1 thereafter.

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B. Annual Forecast of Power Supply Expense

To better match the timing of recovery of power supply expenses with the period in which the power supply expenses are incurred, each March the Company will file its Annual Forecast of Power Supply Expenses. The Annual Forecast will include a current forecast of resources, market prices and fuel expenses consistent with anticipated stream flow conditions for April through March as predicted by the Northwest River Forecast Center. A rate associated with this updated view of prospective power supply expense will be proposed for implementation on June 1 of each year, coincident with the new Annual Base Rate change. The first filing of this component would occur in March 2008.

C. Annual Power Supply Expense True-Up

Recognizing that even the best forecast of power supply expenses will not be perfect, the annual true-up of power supply expenses will correct for any error in the previous year's forecast. Beginning April 2009, the Company will file its Annual Power Supply Expense True-up measuring the deviation between actual net power supply expenses experienced the preceding year, April through March, and the base net power supply expense established in October prior to that water year. This deviation from annual base rates will be adjusted for revenues collected or refunded as a result of the Annual Forecast. On June 1, 2009, and every June 1 thereafter, all three rates will go into effect.

D. Balancing Account

Deviations in actual power supply expenses from forecasted levels will result in net power cost accruals that will be determined on a monthly basis and posted to a balancing account. A positive balance represents money to be recovered by the Company from its customers. A negative balance indicates money the Company will refund to its customers. The balance, either positive or negative, will accrue interest at the rate paid on customer deposits established by the Commission pursuant to OAR 860-021-0210.

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E. Rate Spread and Rate Design

As proposed in Schedule 55, recovery charges and refunds will be spread to customers on a uniform cents per kWh basis to all customer classes in order to reflect changes in costs per kWh incurred by the Company to serve customers.

IV. CONCLUSION

It is in the public interest to approve the requested PCAM. Approval will ensure that the Company's prices will more accurately reflect the actual underlying cost of providing service to its customers in the future. As discussed above, Idaho Power's unique reliance on hydro generation, taken together with multiple drought years and Oregon's limitation on the amortization of deferral balances, has made it impossible for the Company to recover its power supply expenses in a timely manner. Approval of the Company proposed PCAM as an automatic adjustment clause under ORS 757.210(1) would substantially mitigate these problems, allowing the Company a fair and reasonable recovery. For these reasons, Idaho Power respectfully requests that, in accordance with ORS 757.205 and ORS 757.210 the Commission issue its order (1) finding that the proposed PCAM is fair, just and reasonable; and (2) approving the proposed Schedule 55 as an automatic adjustment clause to be implemented at the times and in the manner set forth herein.

Dated: August 17, 2007.

McDowell & Rackner PC

Lisa F. Rackner

Idaho Power Company

Barton L. Kline
Senior Attorney
PO Box 70
Boise, ID 83707

Attorneys for Idaho Power Company

Attachment A

SCHEDULE 55
POWER COST ADJUSTMENT MECHANISM

APPLICABILITY

This schedule is applicable to the electric energy delivered to all Oregon retail Customers served under the Company's schedules and Special Contracts. These loads are referred to as "firm" load for purposes of this schedule.

BASE POWER COST RATE

The Base Power Cost Rate included in the Company's rate schedules is computed by dividing the Company's power cost components determined under normal streamflow conditions, by weather-normalized firm kilowatt-hour (kWh) sales. The power cost components include fuel and purchased power expenses, off-system surplus sales revenue and purchases from cogeneration and small power producers qualified under the Public Utility Regulatory Polices Act of 1978 (PURPA). The Base Power Cost Rate is 0.316 cents per kWh.

ANNUAL BASE RATE UPDATE

The Base Power Cost Rate will be updated annually in October based upon the forecasted "normal" Base Power Cost for the upcoming water year (April through March).

ANNUAL FORECAST OF POWER SUPPLY EXPENSE

The Annual Forecast of Power Supply Expense (Annual Forecast) is the Company's estimate, expressed in cents per kWh, of the power cost components (PURPA and non-PURPA related) for the forecasted water year beginning April 1 each year and ending the following March 31. The Annual Forecast rate for the period beginning April 1, 2008 is 0.00 cents per kWh.

ANNUAL POWER SUPPLY EXPENSE TRUE-UP

The Annual Power Supply Expense True-Up (True-Up) is based upon the difference between the Annual Forecast of net power supply expenses for the previous year, April through March, and the actual net power supply expenses incurred for the same period. The True-Up rate for the period ending March 31, 2007 is 0.00 cents per kWh.

POWER COST ADJUSTMENT

The Power Cost Adjustment is based upon of the difference between the Annual Forecast rate and the corresponding Base Power Cost rate as well as differences between the True-up expenses and the previous year's forecast expenses. Ninety percent of the non-PURPA related differences, plus 100 percent of the PURPA related differences are ultimately included in the Power Cost Adjustment rate.

The monthly Power Cost Adjustment rate for the period beginning April 1, 2008 applied to the energy rate of all metered schedules and Special Contracts is 0.00 cents per kWh. The monthly Power Cost Adjustment rate applied to the per unit charges of the nonmetered schedules is the monthly estimated usage times 0.00 cents per kWh.

BALANCING ACCOUNT

This schedule is an automatic adjustment clause as defined in ORS 757.210 and is subject to review by the Commission at least once every two years. Oregon net power cost amounts will be determined on a monthly basis and posted to a balancing account. An entry into the balancing account will occur in every month, unless the actual net power supply cost is identical to the level in rates. A positive balance represents money to be recovered by the Company from its customers. A negative balance indicates money to be refunded by the Company to its customers. Both positive and negative balances will accrue interest at the customer deposit rate established by the Commission pursuant to OAR-860-021-0210.

EXPIRATION

The Power Cost Adjustment Mechanism will continue from year to year until terminated. The Power Cost Adjustment included on this schedule will expire May 31, 2009.

Idaho Power/100
Witness: Michael J. Youngblood

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE ____

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.	)
	)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

MICHAEL J. YOUNGBLOOD

Q. Please state your name, business address and present position.

A. My name is Michael J. Youngblood. I am employed by Idaho Power Company ("Idaho Power" or the "Company") as a Senior Pricing Analyst in the Pricing and Regulatory Services Department. My business address is 1221 West Idaho Street, Boise, Idaho 83702.

Q. Please describe your educational background.

A. In May of 1977, I received a Bachelor of Science Degree in Mathematics and Computer Science from the University of Idaho. From 1994 through 1996, I was a graduate student in the MBA program of Colorado State University.

Q. Please describe your work experience with Idaho Power.

A. I became employed by Idaho Power in 1977. During my career, I have worked in several departments and subsidiaries of the Company, including Systems Development, Demand Planning, Strategic Planning and IDACORP Solutions. Most relevant to this testimony is my experience within the Pricing and Regulatory Department. From 1981 to 1988 I worked as a Rate Analyst in the Rates and Planning Department where I was responsible for the preparation of electric rate design studies and bill frequency analyses. I was also responsible for the validation and analysis of the load research data used for cost of service allocations.

From 1988 through 1991 I worked in Demand Planning and was responsible for the load research and load forecasting functions of the Company including sample design, implementation, data retrieval, analysis, and reporting. I was responsible for the preparation of the five-year and twenty-year load forecasts used in revenue projections and resource plans as well as the presentation of these forecasts to the public and regulatory commissions.

In 2001, I returned to the Pricing and Regulatory Department and have worked on special projects related to deregulation, the Company's Integrated Resource Plan, and filings with the Oregon Public Utility Commission (the "Commission") regarding the Company's deferral applications for recovery of excess net power supply expenses.

I have provided testimony to the Commission in UE 123/UE 131, UM 1198, and UM 1261.

Q. What is the purpose of your testimony?

A. The purpose of my testimony in this docket is to describe Idaho Power's proposal for a Power Cost Adjustment Mechanism ("PCAM") to be implemented in its Oregon jurisdiction.

Q. Why does the Company believe a PCAM is needed in Oregon?

A. In its Order issued in Idaho Power's last rate case, UE 167, the Commission specifically recognized that Idaho Power's system is uniquely reliant on hydroelectric generation. The order also acknowledges that in Oregon, the Company is uniquely limited in its ability to amortize deferred costs.[1] In fact, over the past several years, the Company has made a number of applications seeking deferred accounting orders and recovery of excess net power supply costs. Company representatives, Commission Staff ("Staff") and representatives of the Citizens' Utility Board of Oregon ("CUB"), have discussed at length the impact of these deferrals and the Company's ability to recover net power supply expenses in a timely manner. In those discussions, the parties have discussed the desirability of developing a PCAM, in order for the Company to better match its revenues to the actual power supply expenses incurred.

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[1] Order No. 05-871, p.7.

Q. Is the PCAM the Company is proposing today a result of those discussions?

A. Yes it is. In conjunction with Mr. Said, and with the input of Staff and CUB, I have developed the mechanism the Company is proposing today.

Q. Would you please give a general description of the PCAM the Company is proposing?

A. The Company is proposing a PCAM that will have three separate and distinct parts. These three parts of the PCAM are intended to accurately align Oregon customers' rates with the actual net power supply expenses incurred. In this way, the objective of aligning the expenses incurred and associated revenues received will be achieved, sending the proper price/cost signal to the customer. The three parts of the PCAM are the: 1) annual update of the base power supply rate ("Annual Base Rate Update" or, alternatively, "Annual Update")); 2) annual forecast of expected power supply expenses ("Annual Forecast of Expected Power Supply Expenses" or, alternatively, "Annual Forecast"); and 3) annual true-up of previous year's power supply expenses ("Annual Power Supply Expense True-Up" or, alternatively "Annual True-Up.").

Q. Please describe the Annual Base Rate Update.

A. Each October, the Company will file its best estimate of "normal" power supply expenses for the upcoming water year, April through March. This estimate will be used to establish the "base" power supply expense rate component associated with the forward test year period. The estimate will include a homogeneous view of forecasted "normal" loads, resources, market prices, and fuel expenses for an average streamflow condition. This new base rate will be implemented on June 1 of the following year.

Q. Based upon current rates, would you please describe how the current base rate would be updated?

A. Based upon the rates currently in effect in Oregon (ordered in UE 167, Order No. 05-871) the current base rate is determined as follows:

		($ million)
	Fuel Expense	$98.4
Plus:	*Purchased Power*	*$14.3*
Less:	*Surplus Sales*	*$114.5*
	NPSE Excluding PURPA Projects	($1.8)
Plus:	*PURPA Projects*	*$46.4*
	Total NPSE	$44.6

Note: NPSE refers to Net Power Supply Expenses

With 2003 sales of 14,107,575 megawatt-hours, the unit cost included in rates has been $3.16 per megawatt-hour (MWh). Idaho Power Exhibit 101 contains my calculations. This is equivalent to 0.316 cents per kilowatt hour.

Q. Please explain the PURPA Project line item.

A. The Company has more than 90 contracts with small qualifying generation facilities ("QFs") that qualify for mandatory energy purchases under the Public Utility Regulatory Policies Act of 1978 ("PURPA"). The Company is proposing that the expenses associated with these mandatory purchases *not* be subject to cost sharing so a separate line item is necessary.

Q. What is the next step in determining the Annual Base Rate Update?

A. If the PCAM is approved, the next step will take place in October 2007, when Idaho Power will file its first Annual Base Rate Update quantifying normal power supply expenses for the April 2008 through March 2009 water year. In doing so, the Company will update its numbers for expected fuel expense, purchased power and surplus sales under normal streamflow conditions. PURPA-related expenses will be added, resulting in the Total Net Power Supply Expense expected for April 2008 through March 2009. The Total Net Power Supply Expense will be divided by the normal megawatt-hour sales to calculate the updated unit cost per MWh. The difference between this updated amount and the $3.16 per megawatt-hour established in UE 167 will be the Annual Base Rate Update for April 2008 through March 2009. This rate, divided by 1,000 to convert to a per kilowatt hour equivalent, will go into effect on June 1, 2008.

Q. Please describe the Annual Power Supply Expense Forecast.

A. Each spring, the Company will file its forecast of the coming water year, April 1 through March 31 in order to establish the "expected" power supply expense. The forecast will include an updated forecast of resources, market prices, and fuel expenses consistent with anticipated streamflow conditions for April through March. A rate associated with this forecast will be proposed for implementation on June 1 of each year, coincident with the new Annual Base Rate Update.

Q. When will the Company file its first Annual Forecast?

A. The Company's proposal will file the first Annual Forecast in March 2008. That Annual Forecast will contain the same components as the Annual Base Rate Update (fuel, purchased power, surplus sales and PURPA-related expenses). However, each of these costs will reflect the most current expectations for the April 2008 through March 2009 water year. The March 2008 Final Water Supply Forecast from the Northwest River Forecast Center in Portland, Oregon will be used to establish expected streamflow conditions. Then-current price information for April 2008 through March 2009 will be used to revise prices. Purchased power prices will be evaluated at the forward heavy load price (on-peak) and surplus sales will use the forward light load price (off-peak), consistent with the prior Commission's Order 05-871 issued in UE 167.

Using these forecasted numbers, the Annual Forecast for net power supply expense will be determined by adding fuel expense, purchased power expense and PURPA costs, then subtracting surplus sales revenue. This Annual Forecast calculated for April 2008 through March 2009 will be divided by the expected megawatt-hour sales to determine the unit cost per MWh. The Company anticipates that a rate adjustment equal to a portion of the difference between the new base rate and the forecast rate would become effective on June 1, 2008. The adjustment will add to or subtract from the base rate set in the Annual Update.

Q. Please describe the Annual Power Supply Expense True-Up.

A. Each April, the Company will file its Annual Power Supply Expense True-Up, measuring the deviation between actual net power supply expenses experienced for the preceding year, April through March, and the base net power supply expense established in October prior to that water year. This deviation from base will be adjusted for revenues collected or refunded by the PCAM during the same period. Revenues associated with load growth would not be included in the true-Up calculation.

Q. How will the Annual Power Supply Expense True-Up be determined?

A. Each month the Company will track the deviations in actual power supply expenses from forecasted net power supply expenses, adjust for revenues collected or refunded by the PCAM for the month, and post the balance in a balancing account. A year-to-date total will show the balance in the account at any point in time. At the end of the year, the balancing account will have either a positive or negative balance. A positive balance means that actual net power supply expenses were greater than the revenue collected by the Company through rates, and will indicate that the Annual Power Supply Expense True-Up will be a surcharge to the customer. A negative balance in the balancing account will indicate that the Company collected more than the actual net power supply expense, and the Annual Power Supply Expense True-Up will be a refund. In either case, the amounts in the balancing account will accrue interest at the rate paid on customer deposits.

Q. How will surcharges or surcredits from the balancing account be allocated to customers?

A. Either a surcharge or surcredit will be spread to customers on a uniform cents per kWh basis to all customer classes in order to reflect the changes in net power supply expenses incurred by the Company to serve its customers.

Q. Will the Company file an Annual Power Supply Expense True-Up in the first year of the PCAM?

A. No. The Annual True-up portion of the PCAM will not go into effect until the second and subsequent years of the PCAM. The Company's first Annual Power Supply Expense True-Up will be filed on or before April 15, 2009. It will be determined by measuring the deviation between actual net power supply expenses experienced for the period April 2007 through March 2008 and the base net power supply expense established in October 2007, less revenues collected by the PCAM during the April 2007 through March 2008 water year. Revenues associated with load growth would not be included in the true-up calculation. This deviation amount, divided by the normalized sales from the October 2008 Annual Base Rate Update calculation, will be the Annual Power Supply Expense True-Up for April 2008 through March 2009. The rate would go into effect on June 1, 2009.

Q. Would you please recap the timing of each of the three parts of the PCAM and when the resulting rate changes would be in effect?

A. Yes. Idaho Power Exhibit 102 provides a graphical representation for the proposed filings and effective period for the rates from each of the three separate parts of the PCAM. As shown in the Exhibit, the first Annual Base Rate Update filing would be in October 2007. The Company anticipates this filing will be subject to a review period through May 2008 with new base rates becoming effective June 1, 2008. The first Annual Forecast will be filed in March 2008, again with the rates effective June 1, 2008. Both of these rates would be in effect from June 1, 2008 through May 31, 2009, a period of one year during which the second Base Rate Update and Forecast Update filings would be made in October and March respectively. In addition to those second filings, in April 2009 the first Annual Power Supply True-Up filing will occur truing-up the deviation from actual net power supply expenses. On June 1, 2009, and every June 1 thereafter, all three rates will go into effect.

Q. Is the Company proposing to share the risk between its customers and shareholders?

A. Yes. Just as the Company's Idaho customers share the risks and benefits associated with a predominately hydro-generation system, the Company is proposing the same sharing for its Oregon customers. All non-PURPA related net power supply expenses above or below the base non-PURPA related net power supply expense will be shared 90/10. The Company's shareholders' will absorb 10% of the additional expenses incurred during higher cost years, usually associated with drought conditions, and the customers will bear 90% of the extra expense. In lower cost years, usually associated with favorable water conditions, the reverse is true, where the Company's shareholders will receive 10% of the benefit and the customers will enjoy 90%.

Q. Why are PURPA costs passed through to customers at 100%?

A. Under PURPA, utilities are obliged to purchase energy from QFs based on a pricing structure referred to as avoided cost rates. The Company has no discretion in purchasing or not purchasing power supplied by QF facilities. Moreover, in Oregon, small QFs must be offered standard rates and standard contracts with no option for negotiation. For these reasons it is not appropriate for the Company's shareholders to receive benefits from or be penalized by those purchases. Recognizing this, the Idaho Commission allows the Company to pass PURPA costs through to Idaho customers at 100%.[2]

Q. Would you please give an example of how an Annual Power Supply Expense True-Up would be calculated?

A. Yes. First assume, for simplicity, that base Net Power Supply Expense (NPSE) is $40 million, PURPA is $60 million, and normalized sales are 10,000,000 MWh. Next, assume that the actual NPSE experienced by the Company is $44 million, actual PURPA costs are $62 million, and normalized sales remained the same (no load growth). The Annual Power Supply Expense True-Up would determine the deviation from base NPSE, without any change associated with load growth. To do this, one would first calculate the base cost per unit of $4.00 ($40,000,000 / 10,000,000 MWh = $4.00 per MWh). Then one would calculate the cost per unit of the increased NPSE of $4.40 ($44,000,000 / 10,000,000 = $4.40 per MWh). The increase in unit costs over the base is $0.40 (Actual NPSE of $4.40 less base NPSE of $4.00). Multiply this per unit increase in NPSE by the base normalized sales to eliminate increases due to load growth to determine

[2] *See* Order No. 24806, issued in Case No. IPC-E-2-25, on Mar. 29, 1993.

the deviation from base NPSE of $4,000,000 ($0.40 per MWh x 10,000,000 MWh = $4,000,000). Multiply this deviation in base by ninety percent to determine the customers' share of $3,600,000.

To this total non-PURPA deferral amount of $3,600,000, the deviation of actual from base PURPA costs of $2,000,000 (Actual PURPA costs of $62,000,000 less base PURPA costs of $60,000,000) is added. The total change in NPSE is $3,600,000 plus $2,000,000 for $5,600,000 on a system basis. The $5,600,000 would be divided by the base normalized sales of 10,000,000 to derive an Annual Power Supply Expense True-Up of $0.56 per MWh. In this example, Idaho Power's customers would see a rate increase of 0.056 cents per kilowatt-hour.

Q. What would happen if normalized sales had also increased in addition to NPSE and PURPA costs?

A. In order to answer this question, let's assume everything is the same as the previous example, but normalized sales increase from 10,000,000 to 12,000,000 MWh, a load growth of 2,000,000 MWh. In this case, the net result would actually be a refund of $1,000,000 on a system basis. The simplified calculation is shown below:

Actual Non-PURPA $/MWh = $44,000,000 / 12,000,000 MWh = $3.67 per MWh

Base Non-PURPA $/MWh = $40,000,000 / 10,000,000 MWh = $4.00 per MWh

Increase (Decrease) from Base = $3.67 - $4.00 = ($0.33) MWh

Non-QF deferral = ($0.33) X 10,000,000 MWh X 90% = ($3,000,000)

QF deferral difference as before = $2,000,000

Total change in NPSE = ($3,000,000) + $2,000,000 = ($1,000,000)

True-Up Rate = ($1,000,000) / 10,000,000 MWh = ($0.10) per MWh or a 0.01 cents per kilowatt-hour refund for the customer.

Q. With regard to the Annual Base Rate Update filed each October, please describe the methodology the Company proposes to determine "normal" net power supply expenses.

A. The Company is proposing a methodology comparable to the one adopted by the Commission in Idaho Power's last general rate case, in Order No. 05-871. The Company will use the latest output of the AURORA model to determine its net power supply average dispatch. Then the Company will use a forward price curve to replace the AURORA determined prices, to set prices for power costs. The Company's purchases will be priced at on-peak prices and its sales at off-peak prices.

Q. What forward price curve does the Company propose to use in setting the base power supply expenses?

A. The Company proposes using a forward price curve for two years in the future. In order to remove the effects of inflation, the values associated with the price curve will be discounted back to the test year months.

Q. Why is the Company proposing to use a forward price curve formulated for so far in the future, as opposed to one formulated for some time in the nearer term?

A. In his testimony, Mr. Said discusses the history behind the use of forward price curves in setting the Company's current retail rates in Oregon. As I will discuss in more detail below, the Company believes that the use of forward price curves is not optimal because—instead of providing an accurate view of prices under "normal" conditions—forward price curves are strongly influenced by current conditions. So for example, during a period of drought, forward price curves for a hydro-based utility like Idaho Power will incorporate an assumption of continuing drought, thus exerting upward pressure on prices.

That said, the Company does believe that the bias created by current conditions is most pronounced in near-term projections, and will lessen the further out the curve projects. In short, as I will also discuss in more detail below, we believe that forward price curves should revert to normal after some period of time. For this reason we are comfortable proposing a price curve for two years out. We believe that this proposal appropriately balances the benefits of setting base rates according to the methodology approved in Order No. 05-871, with the need to remove near-term bias of existing conditions.

Q. How do current forward price curves, which are influenced by current streamflow conditions, impact the determination of "normal" net power supply expenses?

A. If current streamflow conditions are below average, as Idaho Power has experienced in six of the last seven years, then current forward price curves reflect those conditions, at least for the short-term. As a result, projections of future electricity prices are higher than "normal" conditions. Consequently, when a net power supply expense is estimated with inflated (not normal) prices, it "appears" that revenue received from surplus sales will greatly offset the expenses incurred for fuel and purchased power costs. The result is that the Company's net power supply expenses are understated. Idaho Power maintains that this is erroneous and believes that recent history supports this argument.

Q. Why does the Company believe that a forward price curve two years in the future, discounted for inflation, to be a better estimate of a "normal" forward price curve?

A. Forward prices curves are used for trading purposes, and the prices within those price curves are reflective of the traders' perception of near-term supply and demand for electricity. Based upon our discussions with the Company's market risk analysts, Mr. Said and I have concluded that forward price curves, while influenced in the short-term by current conditions, should trend back to a "normal" view of electricity prices in the future. The question is, "how soon do forward price curves return to normal?" Our risk analysts have advised us that the effects of adverse hydro conditions can linger more than a year. Poor hydro conditions, especially multiple years of reduced streamflows, can cause higher prices to persist and it will take a couple of years to return to normal. Recognizing this persistence of adverse water assumptions in forward prices and not wanting to select a forward curve too distant in the future, we chose two years.

Q. **What does your proposed forward rate curve mean for the Company's PCAM proposed today?**

A. For the Annual Base Rate Update filed each October, the Company will file its best estimate of a "normal" expectation for the coming water year, April through March. In doing so, the Company will use an AURORA run which will include more than 80 years of historical hydro conditions, expected loads and resources for the coming water year, allowing AURORA to determine the economic dispatch of the Company's resources. This is consistent with the methodology accepted in the Company's last general rate case, Docket UE 167, Order No. 05-871. Using the average generation dispatch from this run, the Company will replace AURORA pricing with monthly prices from a two-year forward price curve, discounted for inflation, to set prices for power costs with purchases made at on-peak prices and sales made at off-peak prices. The result would establish the "normal" net power supply expenses expected for the coming water year.

Q. **What two-year forward curve would the Company use in its October 2007 filing?**

A. In October 2007, for the coming water year of April 2008 through March 2009, the Company will use an average of the monthly forward price curves for April 2010 through March 2011, discounted for inflation back to April 2008 through March 2009.

Q. Why is the Company proposing to use an average of the monthly forward price curves for April 2010 through March 2011?

A. Forward prices can vary greatly from day to day. In addition, forward prices vary for seasonal fluctuations throughout the calendar year. In order to smooth these daily fluctuations, and yet still maintain a seasonal shape for the forward prices, the Company is proposing to average the daily forward price curves over each month, and use that average for the monthly price. As a result, each month, April 2010 through March 2011, would have an average monthly forward price determined for both heavy load hours and light load hours in order to price normal power purchases and surplus sales, respectively.

Q. Over what period will the two-year forward monthly averages be determined?

A. These two-year forward monthly averages are to be used in the Annual Base Rate Update the Company will file each October. Therefore, in order to smooth the effects of daily variations, the Company will use the one-year period from the preceding October through September to obtain average monthly price curves, two years forward.

Q. Would you please describe in more detail the process that the Company will utilize in determining the forward price curve for the October 2007 Annual Base Rate Update filing?

A. In October 2007 the Company will file its Annual Base Rate Update in order to determine normal net power supply expenses for the period of April 2008 through

March 2009. In that filing, we will use two-year forward price curves for the period of April 2010 through March 2011. Data for those curves will be collected for one year prior to the filing, October 2006 through September 2007. The average monthly prices (for each of the months April 2010 through March 2011) will be calculated by averaging all of the daily price curves for the month. To remove the effects of inflation, each of these monthly average prices will then be discounted back to the period of April 2008 through March 2009, thereby producing the "normal" forward prices to be used to re-price the Company's purchase power and surplus sales estimates for the period April 2008 through March 2009.

Q. How will the Company allocate net power supply expenses between its Idaho and Oregon jurisdictions?

A. The calculation of net power supply expenses is used in determining the Annual Base Rate Update, the Annual Forecast and the Annual Power Supply True-Up. In all cases, NPSE are determined on a system-wide basis. That determination, which may result in either an increase or decrease to base net power supply expenses, will be allocated between the Company's Idaho and Oregon jurisdictions. Currently the Oregon jurisdictional share of that allocation is 4.80%.

Q. You stated before that the Company has had a PCA in its Idaho jurisdiction since 1993. Does that mechanism make use of deadbands around net power supply expenses within which no collection or refund of excess net power supply expenses is allowed?

A. No.

Q. Is the Company proposing deadbands for the PCAM in its Oregon jurisdiction?

A. No. Mr. Said discusses the rationale for that decision in his testimony.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE ____

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.	)))))))

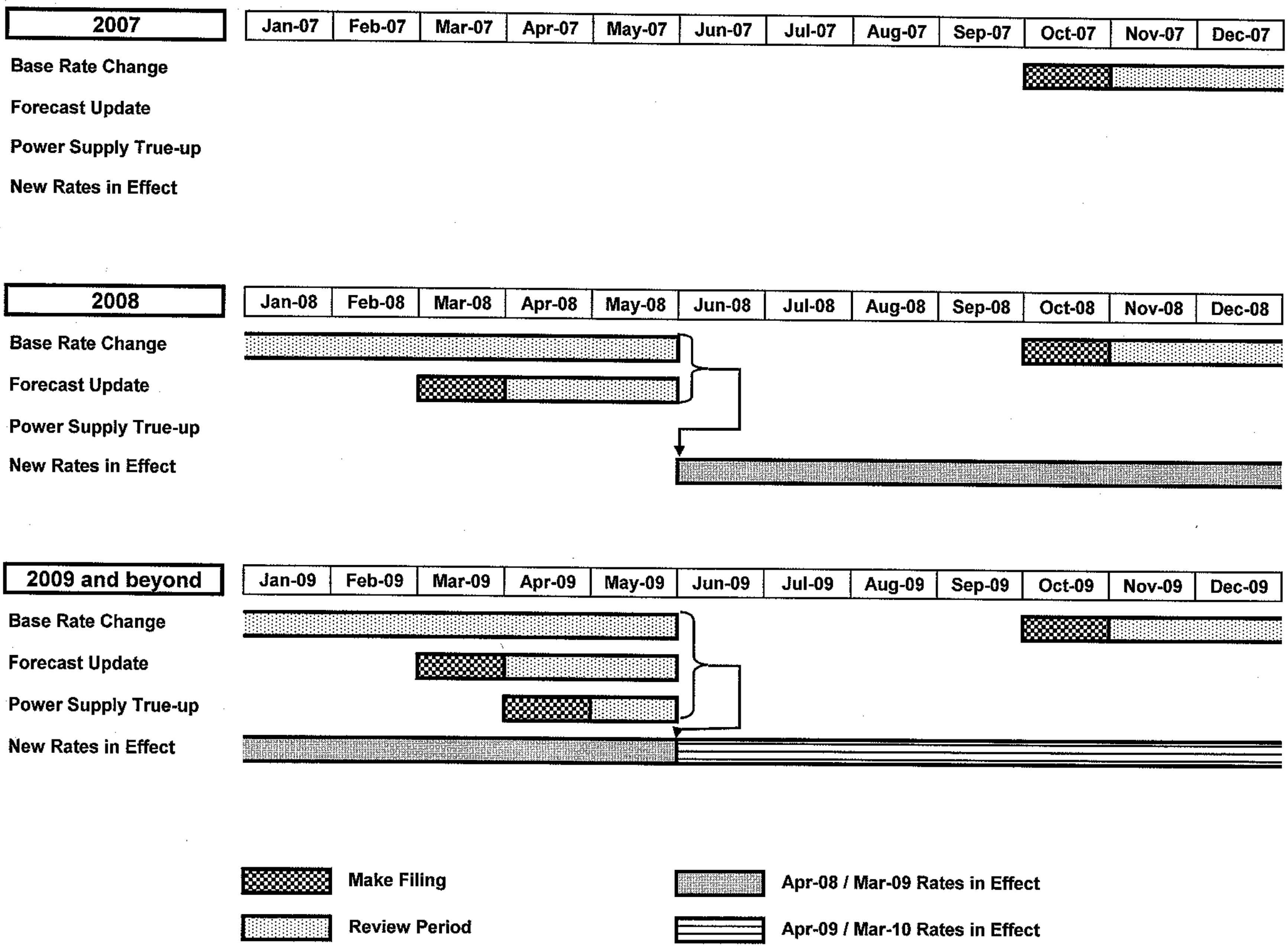
IDAHO POWER COMPANY

EXHIBIT ACCOMPANYING DIRECT TESTIMONY

OF

MICHAEL J. YOUNGBLOOD

Oregon PCAM Filing Schedule



BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE ____

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.	)))))))

IDAHO POWER COMPANY

EXHIBIT ACCOMPANYING DIRECT TESTIMONY

OF

MICHAEL J. YOUNGBLOOD

UE 167 Commission Decision (Order 05-871)
Staff Alternative Adjustment to Idaho Power Exhibit No. 13
Power Supply Expenses Normalized Using Idaho Power's Forward Price Curves from April 30, 2004 (On-peak Prices for Purchases, Off-peak Prices for Sales)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Hydroelectric Generation (mwh)	796,221.1	832,943.3	817,100.1	850,869.7	859,088.5	858,151.1	759,935.6	726,751.7	675,876.1	541,432.4	456,092.1	662,560.9	8,837,022.5
Bridger													
Energy (mwh)	438,772.7	378,579.5	442,661.3	391,177.1	327,570.9	326,888.8	455,772.4	455,868.7	441,499.2	456,599.6	441,577.7	456,158.0	5,013,126.0
Cost ($ x 1000)	$5,593.3	$4,826.0	$5,642.8	$4,986.5	$4,175.7	$4,167.0	$5,810.0	$5,811.2	$5,628.0	$5,820.5	$5,629.0	$5,814.9	$63,904.9
Boardman													
Energy (mwh)	35,892.5	31,118.0	36,441.9	32,832.6	29,961.8	0.0	38,327.3	38,725.3	37,546.0	38,791.7	37,544.3	38,754.2	395,935.6
Cost ($ x 1000)	$475.4	$412.2	$482.7	$434.9	$396.9	$0.0	$507.7	$513.0	$497.4	$513.9	$497.3	$513.4	$5,244.7
Valmy													
Energy (mwh)	162,669.0	145,085.8	78,685.9	114,741.2	151,563.5	148,155.1	163,064.5	163,062.4	157,894.3	162,805.5	157,745.1	163,173.8	1,768,646.1
Cost ($ x 1000)	$2,391.3	$2,132.8	$1,156.7	$1,686.7	$2,228.0	$2,177.9	$2,397.1	$2,397.1	$2,321.1	$2,393.3	$2,318.9	$2,398.7	$25,999.8
Danskin													
Energy (mwh)	10.1	13.8	35.6	8.5	137.6	238.7	149.3	166.9	11.0	5.7	7.0	20.3	804.6
Cost ($ x 1000)	$0.5	$0.7	$1.4	$0.4	$6.6	$11.3	$7.6	$8.0	$0.4	$0.3	$0.3	$0.8	$38.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$272.0	$256.8	$272.0	$264.4	$272.0	$264.4	$272.0	$272.0	$264.4	$272.0	$264.4	$272.0	$3,218.4
Total Cost	$272.5	$257.5	$273.4	$264.8	$278.6	$275.7	$279.6	$280.0	$264.8	$272.3	$264.7	$272.8	$3,256.5
Forward Price Curve (HLH $/MWh)	**$55.80**	**$55.25**	**$54.70**	**$35.19**	**$33.81**	**$34.50**	**$52.11**	**$54.59**	**$50.62**	**$44.66**	**$47.14**	**$49.63**	**$47.33**
Forward Price Curve (LLH $/MWh)	**$48.48**	**$48.00**	**$47.52**	**$28.05**	**$26.95**	**$27.50**	**$43.63**	**$45.71**	**$42.38**	**$37.40**	**$39.47**	**$41.55**	**$39.72**
Purchased Power (Excluding CSPP)													
Market Energy (mwh)	10,978.3	2,425.5	2,126.6	976.7	18,390.4	40,600.1	44,999.7	31,717.5	12,398.6	1,019.0	19,820.4	25,362.5	210,815.2
Contract Energy (mwh)	0.0	0.0	0.0	0.0	0.0	32,400.0	33,480.0	33,480.0	0.0	0.0	0.0	0.0	99,360.0
Total Energy Excl. CSPP (mwh)	10,978.3	2,425.5	2,126.6	976.7	18,390.4	73,000.1	78,479.7	65,197.5	12,398.6	1,019.0	19,820.4	25,362.5	310,175.2
Market Cost ($ x 1000)	**$612.6**	**$134.0**	**$116.3**	**$34.4**	**$621.8**	**$1,400.7**	**$2,344.9**	**$1,731.5**	**$627.6**	**$45.5**	**$934.3**	**$1,258.7**	**$9,862.4**
Contract Cost ($ x 1000)	$0.0	$0.0	$0.0	$0.0	$0.0	$1,400.0	$1,500.0	$1,500.0	$0.0	$0.0	$0.0	$0.0	$4,400.0
Total Cost Excl. CSPP ($ x 1000)	**$612.6**	**$134.0**	**$116.3**	**$34.4**	**$621.8**	**$2,800.7**	**$3,844.9**	**$3,231.5**	**$627.6**	**$45.5**	**$934.3**	**$1,258.7**	**$14,262.4**
Surplus Sales													
Energy (mwh)	$275,833.0	$393,058.0	$386,996.0	$477,141.2	$339,313.2	$244,417.9	$105,904.1	$123,223.1	$229,492.0	$215,052.0	$71,826.3	$162,439.0	$3,024,695.7
Revenue Including Transmission Costs ($ x 1000)	**$13,372.4**	**$18,866.8**	**$18,390.1**	**$13,383.8**	**$9,144.5**	**$6,721.5**	**$4,620.6**	**$5,632.5**	**$9,725.9**	**$8,042.9**	**$2,835.0**	**$6,749.3**	**$117,485.3**
Transmission Costs ($ x 1000)	$275.8	$393.1	$387.0	$477.1	$339.3	$244.4	$105.9	$123.2	$229.5	$215.1	$71.8	$162.4	$3,024.7
Revenue Excluding Transmission Costs ($ x 1000)	**$13,096.5**	**$18,473.7**	**$18,003.1**	**$12,906.7**	**$8,805.2**	**$6,477.1**	**$4,514.7**	**$5,509.3**	**$9,496.4**	**$7,827.9**	**$2,763.2**	**$6,586.9**	**$114,460.6**
Non-QF Net Power Supply Costs ($ x 1000)	**($3,751.5)**	**($10,711.3)**	**($10,331.1)**	**($5,499.3)**	**($1,104.2)**	**$2,944.3**	**$8,324.6**	**$6,723.4**	**($157.5)**	**$1,217.6**	**$6,881.2**	**$3,671.6**	**($1,792.2)**
Idaho Power Exhibit 13 Net Power Supply Costs ($ x 1000)	$3,318.8	$35.3	($441.5)	($1,786.6)	$1,176.5	$4,992.8	$9,944.2	$8,473.1	$3,489.8	$4,053.1	$7,906.2	$6,526.5	$47,688.1
Total Staff Adjustment ($ x 1000)	($7,070.3)	($10,746.6)	($9,889.5)	($3,712.7)	($2,280.7)	($2,048.5)	($1,619.6)	($1,749.7)	($3,647.3)	($2,835.6)	($1,025.0)	($2,854.9)	($49,480.4)
CSPP ($ x 1000)	**$2,164.0**	**$2,073.6**	**$2,292.8**	**$2,815.8**	**$4,160.4**	**$6,508.8**	**$6,702.9**	**$6,422.3**	**$5,081.4**	**$3,792.8**	**$2,204.7**	**$2,193.5**	**$46,413.1**
Net Power Supply Costs ($ x 1000)	**($1,587.5)**	**($8,637.7)**	**($8,038.3)**	**($2,683.6)**	**$3,056.2**	**$9,453.1**	**$15,027.5**	**$13,145.7**	**$4,923.9**	**$5,010.4**	**$9,085.9**	**$5,865.1**	**$44,620.8**
Load (in 000s MWH)	**1,207**	**1,033**	**1,040**	**974**	**1,142**	**1,259**	**1,492**	**1,425**	**1,179**	**1,056**	**1,080**	**1,220**	**14,108**
Hours in Month	**720**	**744**	**720**	**744**	**744**	**720**	**744**	**720**	**744**	**744**	**672**	**744**	**8,760**
Unit Cost / MWH (for PCA)	**($1.32)**	**($8.36)**	**($7.73)**	**($2.76)**	**$2.68**	**$7.51**	**$10.07**	**$9.23**	**$4.18**	**$4.74**	**$8.41**	**$4.81**	**$3.16**

Idaho Power/200
Witness: Gregory W. Said

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE ____

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.	)
	)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

GREGORY W. SAID

Q. Please state your name and business address.

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

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

A. I am employed by Idaho Power Company ("Idaho Power" or the "Company") as the Manager of Revenue Requirement in the Pricing and Regulatory Services Department.

Q. Please describe your educational background.

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

Q. Please describe your work experience with Idaho Power.

A. I became employed by Idaho Power in 1980 as an analyst in the Resource Planning Department. I developed power supply modeling for use in determining the average net power supply expenses associated with multiple hydro conditions that was utilized by both the Idaho Public Utility Commission (the "Idaho Commission") and the Oregon Public Utility Commission (the "Commission") in determining the Company's jurisdictional revenue requirements for the 1981 test year. In 1985, the Company applied for a general revenue requirement increase in both Idaho and Oregon. I was the Company witness addressing power supply expenses.

In August of 1989, after nine years in the Resource Planning Department, I was offered and I accepted a position in the Company's Rate Department. With the Company's application for a temporary rate increase in Idaho in 1992, my responsibilities as a witness were expanded. While I continued to be the

Company witness concerning power supply expenses, I also sponsored the Company's rate computations and proposed tariff schedules in that case. Also in 1992, I developed a "Power Cost Adjustment Analysis" report that the Company filed with the Idaho Commission on September 11, 1992. Later that year on November 24, 1992, the Company applied for authority to implement a power cost adjustment ("PCA") in its Idaho jurisdiction. I was the Company witness addressing the specific mechanism features proposed by the Company.

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

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

A. The purpose of my testimony is to provide the Commission with an overall context for the Company's Power Cost Adjustment Mechanism ("PCAM") proposal and the policy decisions that shape the proposal.

Q. You have testified that the Company applied for authority to implement a power cost adjustment in its Idaho jurisdiction in 1992. What were the factors that led to that application?

A. In the late 1980s and early 1990s, the Company experienced a prolonged period of drought which resulted in multiple years where the Company's system power supply expenses greatly exceeded its "normalized" power supply expenses included in base rates. As a result the Company applied for a series of drought-related surcharges. While the Company was granted rate relief, several parties pointed out the Company had not reduced rates during periods of low system power supply expenses that had accompanied the abundant water conditions that existed in the early 1980s. This asymmetric approach of seeking surcharges when power supply expenses were high, but not requesting rate relief when power supply expenses were low, prompted the Idaho Commission to order the Company to evaluate a power cost adjustment mechanism. Following a lengthy proceeding, the Idaho Commission approved the Idaho Power Cost Adjustment ("Idaho PCA") that has been in existence in Idaho for 15 years.

Q. **You mentioned that Idaho Power's system power supply expenses are related to variation in water conditions. Is the Idaho PCA an adjustment related solely to water conditions?**

A. No. Although water conditions greatly affect Idaho Power's power supply expenses, the Idaho PCA considers all factors that ultimately affect system power supply expenses including changes in fuel prices, purchased power prices, surplus sales prices and resource availability.

Q. **What level of volatility of system power supply expenses did the parties to the Idaho PCA case consider when the Idaho PCA was created in 1992?**

A. Based on then-current analysis, the parties expected that, depending upon water and market conditions, the Company's system power supply expenses could vary by over $100 million from the worst of conditions to the best of conditions.

Q. **What level of volatility of system power supply expenses does the Company anticipate today?**

A. Based upon its current Idaho filing, the Company now anticipates system power supply expenses that can vary annually by over $400 million. Idaho Power Exhibit 201 shows how that expected variance was determined.

Q. **What is the annual system revenue requirement of the Company?**

A. Based upon information contained in the Company's pending Idaho General Rate Case filing (IPC-E-07-8), based upon a 2007 test year, the annual system revenues required from jurisdictional sales and wheeling revenues is approximately $732 million. This includes $174 million of return on investments based upon an assumed authorized rate of return on equity of 11.5%. Assuming that normalized power supply expenses are set at the midpoint of the $400 million of variability, it can be seen that without PCAMs, the Company's actual returns could be totally eliminated or more than doubled by prevailing conditions.

Q. Did the Company propose a PCAM in Oregon in 1992?

A. No. Based upon discussions with Commission Staff, the Company understood that the Commission did not believe that PCAMs were in the public interest at that time.

Q. Why is the Company requesting a PCAM in Oregon now?

A. Similar to the events that occurred in Idaho 15 years ago, recurring drought conditions over multiple years have forced the Company to request multiple excess power supply expense deferrals in Oregon. Because of the small size of the Company's revenues in Oregon and Oregon law limiting amortization of deferral balances, these deferrals are subject to prolonged amortization periods. This process results in a shift of the extraordinary costs to serve current Oregon customers on to later generations of customers. The Company believes that in UE 167[1] the Commission has indicated a desire to resolve this issue to ensure that the customers that use energy today are responsible for paying for the costs that are incurred on their behalf—rather than passing those costs on to future customers. Additionally, a PCAM will allow current customers to benefit from lower rates when conditions drive actual power supply expenses below normalized levels included in rates.

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[1] Order No. 05-871, p.7.

Q. You have mentioned that "normalized" levels of power supply expenses are included in the Company's base rates. Why are normalized power supply expenses used in setting rates?

A. As I have discussed, actual annual power supply expenses can vary to a great degree depending upon water and market conditions. For purposes of base rate determinations, commissions seek to identify the central tendency of potential variation in system power supply expenses such that over time the average of the actually experienced power supply expenses will equal the normalized level. For a system with small variance in power supply expenses, power supply related risk is low and a PCAM would not be of substantive value. However, for Idaho Power with its high variation in power supply expenses from condition to condition, a PCAM is of significant value to both the Company and its customers.

Q. Please provide an overview of the Oregon PCAM features that the Company is proposing.

A. The three primary features of the Company's proposed Oregon PCAM are: 1) an annual update of base level (normalized) power supply expenses—the Annual Base Rate Update (or, alternatively, "Annual Update") ; 2) an annual forecast of expected power supply expenses—the Annual Power Supply Expense Forecast; (or, alternatively, "Annual Forecast"); and 3) an annual true-up of previous year power supply expenses—the Annual Power Supply Expense True-Up (or, alternatively, "Annual True-Up").

Q. Please describe the purpose of the Annual Base Rate Update.

A. The primary purpose of the annual update of base level (normalized) power supply expenses is to address the impacts of load growth and resource acquisition on power supply expenses. It is important to note that only the variable costs of resource acquisition would be updated. Recovery of fixed costs and returns related to resource acquisition would need to be addressed in a separate proceeding.

Q. **Would the Annual Base Rate Update be consistent with the Commission's determination of normalized power supply expenses in the Company's last Oregon jurisdictional revenue requirement case?**

A. Yes. In the Company's last general rate case in Oregon, the Commission was unwilling to accept the full results of Idaho Power's AURORA power cost modeling in setting normal future market prices but was willing to accept Staff's proposal to adjust AURORA results by utilizing forward price curves as representative of normal future power prices. While the Company believes that the use of forward price curves as representations of normal market prices is not an optimal long-term solution, the Company does not want this issue to delay the adoption of its PCAM. Therefore, at this time the Company is proposing to utilize forward price curves for determining normalized power supply expenses. The Company anticipates that it will be able to demonstrate in a future Oregon rate case that its power supply cost modeling is sufficiently accurate to replace the use of the forward price curves in both PCAM and the general rate case filings. Mr. Youngblood testifies to the specifics and timing of the Annual Base Rate Update.

Q. **Please describe the purpose of the Annual Forecast.**

A. The primary purpose of the annual forecast of expected power supply expenses is to attempt to match the timing of recovery of power supply expenses with the period in which the power supply expenses are incurred. The forecast will be the Company's best estimate of what power supply expenses will actually be compared to the updated base level of power supply expenses. Mr. Youngblood testifies to the specifics and timing of the annual forecast.

Q. **Please describe the purpose of the Annual Power Supply Expense True-up of power supply expenses.**

A. Recognizing that even the best forecast of power supply expenses will not be perfect, the Annual Power Supply Expense True-up will correct for any error in the previous year's forecast. This ensures that ultimate PCAM recovery is not tied to the accuracy or inaccuracy of the forecast. Mr. Youngblood testifies to the specifics and timing of the annual true-up.

Q. **If ultimately the forecast is corrected after the fact, why is a forecast needed in the first place?**

A. The forecast is intended to match the responsibility for power supply expenses incurred with the customers who receive the benefits of the energy provided. A PCAM based solely upon a true-up shifts the costs or benefits derived in any given year to consumers on the system in the following year. This substantially mutes the price signal provided by a PCAM.

Q. **Is the Company proposing a deadband for purposes of the forecast and true-up features of the Oregon PCAM?**

A. No. The Company believes that symmetric treatment of power supply expense deviation from normal levels is threatened by dead bands. Asymmetry arises from improper setting of base levels which, as I have testified, remains a concern of the Company. In addition, the Company believes that deadbands reduce the effectiveness of a properly designed PCAM. The Company has had a PCA in its Idaho jurisdiction since 1993 that does not use deadbands. The mechanism in Idaho has been well established and has worked well in achieving its objectives of giving appropriate and timely price signals during drought conditions as well as providing customers with financial benefits during times when streamflows are above normal and opportunities for sales of surplus energy are enhanced.

Deadbands can have the perverse effect of introducing an incentive to set base net power supply expenses artificially low. Setting base net power supply expenses artificially low penalizes the Company and its shareholders and fails to provide the appropriate price signals to the Company's customers at times when such signals are needed. If the Company's net power supply expenses are set at an artificially low level, then the Company's actual NPSE will always be greater than the base. Consequently, the Company will always be lagging in recovery of its NPSE, and will always be subject to non-recovery of a portion of its expenses above the base. If deadbands are not present, it is in everyone's best interest to set the base NPSE as close to actual as possible. In that way the Company recovers appropriately incurred expenses above the NPSE and the Company's customers enjoy the benefits of net power supply expenses falling below the base NPSE. With a properly set base NPSE, it is appropriate to assume that both collections and refunds would occur. Deadbands have the effect of negating that assumption and take away the value of symmetry around the base. The Company does not agree with the use of deadbands, and is not proposing deadbands in this Oregon PCAM application.

Q. **Does a PCAM eliminate the Company incentive to optimally manage the system if the proposed PCAM is approved?**

A. No, the Company has a 10% interest in all power supply transactions under its control. Based upon a potential variance of over $400 million in power supply expenses, the Company still has a strong incentive to manage its system optimally.

Q. What level of sharing of deviations in power supply expenses from normal levels does the Company propose?

A. The Company proposes that deviations in power supply expenses attributable to power purchase contracts required by the Public Utility Regulatory Policies Act of 1978 ("PURPA") be passed through 100% to customers. The Company has no control over PURPA production and is required to take all power produced by PURPA facilities at Commission-approved rates.

The Company proposes that deviations in other power supply expenses such as fuel, purchased power, and surplus sales, each of which the Company does have some ability to affect, be shared 90% by customers and 10% by the Company.

Q. Does that conclude your testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE ____

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.	)))))))

IDAHO POWER COMPANY

EXHIBIT ACCOMPANYING DIRECT TESTIMONY

OF

GREGORY W. SAID

PCA REGRESSION DERIVATION

obs.	year	runoff	ln(runoff)	npsc	predicted y
1	1928	6,687,539	15.72	$ (49,036,728)	$ (16,526,734)
2	1929	3,361,059	15.03	$ 72,404,631	$ 112,153,230
3	1930	2,707,422	14.81	$ 149,115,339	$ 152,601,807
4	1931	2,222,506	14.61	$ 220,492,801	$ 189,515,836
5	1932	4,654,741	15.35	$ 99,378,119	$ 51,248,136
6	1933	4,194,946	15.25	$ 122,106,002	$ 70,701,135
7	1934	2,363,549	14.68	$ 248,715,179	$ 178,007,639
8	1935	3,087,643	14.94	$ 193,493,591	$ 128,022,984
9	1936	5,003,688	15.43	$ 89,411,191	$ 37,727,374
10	1937	2,952,686	14.90	$ 138,510,123	$ 136,382,229
11	1938	6,859,391	15.74	$ 873,457	$ (21,272,397)
12	1939	3,784,338	15.15	$ 61,041,015	$ 89,967,796
13	1940	4,188,408	15.25	$ 65,597,495	$ 70,992,851
14	1941	3,767,989	15.14	$ 84,518,332	$ 90,777,532
15	1942	4,888,149	15.40	$ 53,628,490	$ 42,096,854
16	1943	9,052,071	16.02	$ (52,050,171)	$ (73,151,921)
17	1944	3,318,538	15.02	$ 66,658,181	$ 114,534,511
18	1945	4,671,061	15.36	$ (1,882,260)	$ 50,593,501
19	1946	6,766,869	15.73	$ (25,515,382)	$ (18,732,387)
20	1947	5,205,971	15.47	$ 3,249,083	$ 30,314,879
21	1948	5,805,875	15.57	$ 19,933,011	$ 9,915,809
22	1949	5,334,181	15.49	$ 12,680,198	$ 25,764,438
23	1950	6,400,584	15.67	$ (14,503,899)	$ (8,323,884)
24	1951	6,470,770	15.68	$ (38,277,571)	$ (10,363,696)
25	1952	10,299,443	16.15	$ (45,105,147)	$ (97,297,760)
26	1953	5,921,638	15.59	$ (8,401,676)	$ 6,223,170
27	1954	5,507,005	15.52	$ 44,113,080	$ 19,800,629
28	1955	3,483,175	15.06	$ 79,052,448	$ 105,478,199
29	1956	7,815,174	15.87	$ (9,694,474)	$ (45,671,183)
30	1957	7,798,559	15.87	$ (41,055,492)	$ (45,273,100)
31	1958	7,433,507	15.82	$ 4,537,568	$ (36,306,309)
32	1959	3,816,887	15.15	$ 79,771,719	$ 88,365,957
33	1960	4,245,918	15.26	$ 67,144,828	$ 68,442,173
34	1961	3,092,766	14.94	$ 147,757,167	$ 127,712,887
35	1962	4,484,164	15.32	$ 56,131,463	$ 58,231,034
36	1963	4,557,294	15.33	$ 27,930,306	$ 55,205,351
37	1964	5,552,348	15.53	$ (5,181,574)	$ 18,266,931
38	1965	8,419,011	15.95	$ (61,254,778)	$ (59,591,476)
39	1966	3,496,728	15.07	$ 61,888,130	$ 104,751,836
40	1967	4,703,464	15.36	$ 33,796,340	$ 49,300,528
41	1968	3,359,176	15.03	$ 32,084,576	$ 112,258,008
42	1969	6,814,487	15.73	$ 4,843,071	$ (20,043,945)
43	1970	6,133,178	15.63	$ (69,166,693)	$ (341,847)
44	1971	10,273,883	16.15	$ (82,286,587)	$ (96,833,026)
45	1972	7,762,679	15.86	$ (17,419,532)	$ (44,410,594)
46	1973	3,888,739	15.17	$ (13,601,979)	$ 84,877,736
47	1974	9,594,874	16.08	$ (25,728,835)	$ (84,044,126)
48	1975	8,059,885	15.90	$ (86,733,954)	$ (51,437,921)
49	1976	7,195,918	15.79	$ (24,482,755)	$ (30,230,598)
50	1977	2,145,455	14.58	$ 167,557,270	$ 196,115,225
51	1978	5,101,863	15.45	$ 17,303,483	$ 34,093,124
52	1979	3,888,971	15.17	$ 24,610,032	$ 84,866,574
53	1980	5,857,990	15.58	$ (20,503,948)	$ 8,244,420
54	1981	4,187,686	15.25	$ 28,000,685	$ 71,025,095
55	1982	9,300,223	16.05	$ (71,602,289)	$ (78,210,310)
56	1983	9,961,651	16.11	$ (113,962,166)	$ (91,060,619)
57	1984	11,380,893	16.25	$ (133,601,575)	$ (115,972,726)
58	1985	5,536,238	15.53	$ (37,267,334)	$ 18,810,404
59	1986	8,440,084	15.95	$ (82,356,653)	$ (60,059,044)
60	1987	3,027,757	14.92	$ 77,803,397	$ 131,686,280
61	1988	2,517,105	14.74	$ 176,517,042	$ 166,234,487
62	1989	4,313,993	15.28	$ 81,915,375	$ 65,467,147
63	1990	2,907,440	14.88	$ 173,776,782	$ 139,270,495
64	1991	2,700,662	14.81	$ 184,527,391	$ 153,069,378
65	1992	1,929,239	14.47	$ 281,582,048	$ 215,983,425
66	1993	6,041,043	15.61	$ (15,166,572)	$ 2,489,240
67	1994	2,527,031	14.74	$ 150,009,571	$ 165,498,412
68	1995	6,610,055	15.70	$ (14,674,727)	$ (14,347,019)
69	1996	8,090,881	15.91	$ (15,479,954)	$ (52,155,837)
70	1997	10,046,261	16.12	$ (48,647,010)	$ (92,642,530)
71	1998	8,405,908	15.94	$ (82,745,532)	$ (59,300,152)
72	1999	7,707,677	15.86	$ (13,139,464)	$ (43,080,622)
73	2000	4,302,602	15.27	$ 30,625,237	$ 65,961,679
74	2001	2,389,491	14.69	$ 196,360,000	$ 175,965,908
75	2002	3,361,015	15.03	$ 165,758,399	$ 112,155,658
76	2003	3,567,043	15.09	$ 161,216,088	$ 101,028,048
77	2004	3,147,333	14.96	$ 164,595,292	$ 124,441,731
78	2005	3,571,629	15.09	$ 145,257,377	$ 100,787,743
averages		5,390,065	15.40	$ 41,624,945	$ 41,624,945

regression statistics

multiple r	0.9128
r square	0.8332
adjusted r square	0.8310
standard error	37,400,000
observations	78
anova	
	df
regression	1
residual	76
total	77
coefficients	
Intercept	2,922,910,107
x variable 1	(187,037,566)