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July 31, 2009

VIA ELECTRONIC FILING
AND HAND DELIVERY

PUC Filing Center
Public Utility Commission of Oregon
PO Box 2148
550 Capitol Street NE, Suite 215
Salem, OR 97308-2148

Re: Docket No. UE ______
In the Matter of the Application of Idaho Power Company for Authority to Increase its Rates and Charges for Electric Service in the State of Oregon

Enclosed for filing by Idaho Power Company are an original and 30 copies of the Application of Idaho Power Company for Authority to Increase its Rates and Charges for Electric Service in the State of Oregon, including the following proposed tariff pages associated with the Company's Tariff P.U.C. OR No. E-27 applicable to electric service in the State of Oregon, together with the Pretrial Brief, supporting direct testimony and exhibits. The tariffs reflect an effective date of August 31, 2009. Provided on the enclosed CD is an electronic version of the workpapers in their original format, when available.

Original Sheet No. A-1	Rule A	Introduction
Original Sheet No. B-1	Rule B	Definitions
Original Sheet No. B-2	Rule B	Definitions
Original Sheet No. C-1	Rule C	Service and Limitations
Original Sheet No. C-2	Rule C	Service and Limitations
Original Sheet No. D-1	Rule D	Metering
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Original Sheet No. 98-1	Schedule 98	Residential and Small Farm Energy Credit

It is respectfully requested that all data requests regarding this matter be addressed to:

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Idaho Power waives paper service in this docket. Please address all communications related to this filing to:

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Please direct informal correspondence and questions regarding this filing to Lisa Rackner at (503) 595-3925.

A copy of this filing has been served on all parties to Idaho Power's last general rate case proceeding, UE 167, as indicated on the attached certificate of service.

Very truly yours,

Lisa Rackner

cc: Service List

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of **Application of Idaho Power Company for Authority to Increase its Rates and Charges for Electric Service in the State of Oregon** on the parties of record from Idaho Power's last general rate case, Docket UE 167, on the date indicated below, by email and U.S. First Class Mail.

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DATED: July 31, 2009

Lisa Rackner

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**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

UE_____

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE IN THE STATE OF OREGON.	**IDAHO POWER COMPANY'S PRETRIAL BRIEF**

I. INTRODUCTION

Idaho Power Company ("Idaho Power" or "Company"), hereby files a general rate increase with the Public Utility Commission of Oregon ("Commission"), pursuant to ORS 757.205 and 757.220, to revise its schedules of rates and charges for electric service in the State of Oregon to become effective with service provided on and after August 31, 2009. The revised rates produce revenues necessary to sustain the provision of stable, reliable, and low-cost electric service to customers in the State of Oregon while preserving the Company's ability to attract capital for future investments in system infrastructure. The Company files this brief in accordance with OAR 860-013-0075.

Idaho Power is an Idaho corporation whose principal place of business is 1221 West Idaho Street, Boise, Idaho 83702. Idaho Power is an electric company and a public utility providing electric service in the State of Oregon within the meaning of ORS 757.005. Idaho Power is subject to the jurisdiction of this Commission, the Idaho Public Utilities Commission, and the Federal Energy Regulatory Commission. The Company provides electric service to approximately 18,251 customers in the State of Oregon and approximately 483,195 total customers in Idaho and Oregon. In conducting its utility business, Idaho Power operates an interconnected and integrated system.

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II. CASE SUMMARY

A. The Test Year

The Company's test year is the twelve months ending December 31, 2009 ("Test Year" or "2009 Test Year"). Idaho Power provides information for a historical base period of twelve months ending December 31, 2008, and a forecast calendar year 2009 which is the test period. In order to meet the legal requirement that rates be fair, just, reasonable, and sufficient, the Company has selected a test year that closely reflects the investment and expense levels that will exist at the time new rates are implemented. The new rates are filed with a requested effective date of August 31, 2009. Assuming application of the full nine-month statutory suspension period to the 30-day effective date now contained in the tariffs, the new rates would become effective May 31, 2010. The Company believes that the 2009 Test Year will provide fair representation of the Company's investments and expenses that will exist at the time that new rates become effective upon completion of this case.

B. Return on Equity

In the Company's last Oregon general rate case, Docket No. UE 167, the Commission approved a return on equity ("ROE") of 10.00 percent. The actual ROE earned by the Company over the last five years has been less than 9 percent on a system-wide basis. During the same period of time, the implied ROE for the Oregon jurisdiction has been less than 5 percent. In this case, the Company seeks an ROE of 11.25 percent. This conservative request is necessary to maintain the financial integrity of the Company while ensuring its ability to provide safe, efficient, and reliable service to its Oregon customers with minimal rate impact. To achieve the 11.25 percent ROE, an Oregon jurisdictional revenue increase of $7.3 million is necessary. The proposed rate increase constitutes an average overall price increase of 22.6 percent in base rates. Even with this requested rate increase, the Company's Oregon customers will continue to benefit from some of the lowest electricity rates in the nation.

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C. Factors Driving Rate Adjustment

Two of the key factors driving the rate adjustment sought in this case are the Company's continued investments in plant and the increasing discrepancy between growth in expenses and revenues since the last test year, 2003.

1. Investment in Plant

The Company's continued investment in plant is the most significant factor contributing to the rate adjustments sought in this case. Since the last general rate case—based upon a 2003 test period—Idaho Power's plant investment increased by approximately $800 million. This increase reflects the addition of key resources for the benefit of Idaho Power customers. These resources include two simple-cycle gas-fired peaking plants, new construction at 21 substation sites, the addition of 1,975 pole-miles of distribution line, and capacity expansion or new construction affecting 95 pole-miles of transmission line. Today the Company's generation system has a nameplate capacity of 3,267 megawatts compared to 2,912 megawatts at the start of 2003—an increase of approximately 12 percent.

Taking accumulated depreciation into effect, net additions to rate base since 2003 have been approximately $600 million. Without any change to the currently authorized ROE of 10.00 percent, this amounts to an additional $3.7 million, an 11.5 percent increase, in Oregon jurisdictional revenues related solely to new Oregon jurisdictional rate base. All of the resources the Company has included in rates for this case reflect prudently incurred costs for resources that are used and useful in providing service to the Company's Oregon customers, or will be used and useful for service prior to the effective date of the rates.

2. Oregon Growth in Expenses Versus Growth in Revenues

Another key driver of the need for an increase in Oregon jurisdictional revenue requirement is the difference between growth in Oregon jurisdictional expenses, excluding power supply expenses, and the growth in Oregon jurisdictional revenues since the last test year, 2003. Growth in expenses has outpaced growth in revenues during this time period by

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$2.1 million, resulting in the need for an additional 6.3 percent increase in Oregon jurisdictional revenues.

3. Return on Equity

The Company's recommendation for an increase in the authorized rate of ROE as discussed above results in an additional revenue requirement of $1.5 million, a 4.8 percent increase in Oregon jurisdictional revenues. As previously stated, the Company's request of an 11.25 percent ROE is necessary to maintain the financial integrity of the Company while ensuring its ability to provide safe, efficient, and reliable service to its Oregon customers with minimal rate impact.

4. Net Power Costs

For purposes of determining the Company's Oregon jurisdictional revenue requirement in this case, the 2008 October Update of normalized power supply expenses from the Company's approved Annual Power Cost Update ("APCU") has been utilized. The Company's normalized power supply expenses are $59.1 million higher than the last APCU October Update of $163.8 million. This dramatic increase is caused by several factors including the changes in market prices for electricity and Oregon's treatment of PURPA contract expenses. Despite the significant increase in net power costs since the last October Update, the Company is not seeking recovery of those increased costs at this time. The previously noted increases to rate base, combined with the Company's request to increase its return on equity percentage along with the growth of expenses over time, amount to a sizeable increase to Oregon customers even without a normalized power supply expense update at this time. While it is important for the Company to have properly reflected normalized power supply expenses included in its base rates over time, given the size of the requested rate increase, the Company will wait until its 2009 October Update to adjust the normalized power supply expenses.

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III. TESTIMONY SUMMARY

The Company's direct case consists of the testimony and exhibits of twelve witnesses:

Gregory W. Said, Director of State Regulation, provides a general overview of the case and introduces the Company witnesses and briefly describes their testimony. Mr. Said also discusses the Company's general regulatory policy.

William Avera, President of FINCAP, Inc., testifies concerning the Company's cost of equity. He will present support for the requested authorized ROE of 11.25 percent. In support of the requested ROE, Mr. Avera examines relevant risk factors applicable to the Company and calculates the recommended ROE range for Idaho Power based upon standard financial methodologies.

Steven Keen, Vice President and Treasurer, builds on Mr. Avera' s testimony by more specifically addressing the relevant risk factors impacting the Company. Mr. Keen discusses the factors that contributed the Company's selection of 11.25 percent and the appropriate ROE.

Douglas Jones, Regulatory Accounting and Support Team Leader, provides testimony regarding audited financial information including levels of investment and expenses for the twelve-month period ending December 31, 2008.

Catherine Miller, Director of Strategic Analysis, describes the methods for estimating the 2009 Test Year levels of investment and expenses based upon the actual 2008 levels provided by Mr. Jones.

Scott Wright, Pricing Analyst, testifies regarding the power supply expenses normalized for the 2009 Test Year. Mr. Wright also describes the current quantification of normalized power supply expenses and contrasts these values to the quantification of normalized power supply expenses currently reflected in the Company's rate base plus the October Update portion of the APCU rate effective June 1, 2009.

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Jeannette Bowman, Senior Pricing Analyst, testifies as to the Company's Oregon jurisdictional revenue requirement and revenue deficiency computations.

Timothy Tatum, Manager of Cost of Service, provides testimony describing the Company's ClassCost-of-Service Study, and describes the spread of the Oregon jurisdictional revenue requirement to customer classes.

Courtney Waites, Pricing Analyst, describes the Company's proposed rate design for the Residential customer class.

Darlene Nemnich, Senior Pricing Analyst, describes the Company's proposed rate design for Small General Service, Large General Service, and Large Power Service customer classes.

Scott Sparks, Senior Pricing Analyst, describes the Company's proposed rate design for Irrigation service and for all remaining customer classes.

Michael Youngblood, Manager of Rate Design, provides testimony regarding the various rate proposals for the different customer classes and describes the proposed changes to the administrative rules and other miscellaneous issues. Mr. Youngblood also provides a summary of the revenue impacts of the Company's proposed rates on each of the Company's Oregon retail rate classes.

Pursuant to OAR 860-013-0075(b), attached as Exhibit A is the summary setting forth the information required to be filed in connection with applications for general rate increases.

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IV. CONCLUSION

The Company requests that the Commission issue an order approving of the proposed rate changes and approving the proposed tariffs.

DATED: July 31, 2009.

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Lisa F. Rackner

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Attorneys for Idaho Power Company

Exhibit A
Summary of Requested Electric General Rate Increase
Oregon Jurisdiction
Filed July 31, 2009

Total Revenues Collected Under Proposed Rates:	$39,762,693
Revenue Change Requested:	$ 7,329,001
Revenues Net of any Credits from Federal Agencies:	$ 7,329,001
Percentage Change in Revenues Requested:	22.60%
Percentage Change in Revenues Net of any Credits from Federal Agencies:	22.60%
Test Period:	Calendar Year 2009
Requested Rate of Return on Capital:	8.68%
Requested Rate of Return on Equity:	11.25%
Proposed Rate Base:	$110,780,820
Results of Operation[1]	
Before Proposed Rate Change	
Utility Operating Income:	$ 4,661,821
Average Rate Base:	$107,853,874
Rate of Return on Capital:	4.322%
Rate of Return on Equity:	2.783%
After Proposed Rate Change[2]	
Utility Operating Income:	$ 9,615,775
Average Rate Base:	$110,780,820
Rate of Return on Capital:	8.68%
Rate of Return on Equity:	11.25%
Effect of Rate Change on Each Customer Class	
Residential Service:	37.34%
Small General Service:	41.16%
Large General Service, Secondary Voltage:	9.80%
Large General Service, Primary Voltage:	22.19%
Area Lighting Service:	0.00%
Large Power Service, Primary Voltage:	8.75%
Large Power Service, Transmission Voltage:	0.00%
Irrigation Service:	44.69%
Unmetered General Service:	24.11%
Municipal Street Lighting Service:	12.46%
Traffic Control Lighting Service:	61.55%

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[1] Based upon the Company's 2008 Report of Operations, updated to reflect annualized revenue from the October portion of the Annual Power Cost Update.

[2] Based upon the Company's 2009 general rate case filing.

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BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE _______

IN THE MATTER OF THE APPLICATION)
OF IDAHO POWER COMPANY FOR)
AUTHORITY TO INCREASE ITS RATES)
AND CHARGES FOR ELECTRIC)
SERVICE IN THE STATE OF OREGON.)
)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

GREGORY W. SAID

July 31, 2009

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 as the Director of State Regulation.

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 Executive Course at the University of Idaho. Over the years I have attended numerous industry conferences and training sessions.

Q. Please describe your work experience with Idaho Power Company.

A. I became employed by Idaho Power Company ("Idaho Power" or "Company") in 1980 as an analyst in the Resource Planning Department. In 1985, the Company applied for a general revenue requirement increase. 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 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.

Because of my combined Resource Planning and Rate Department experience, I was asked to design a Power Cost Adjustment ("PCA") which would impact customers' rates based upon changes in the Company's net power supply expenses. I presented my recommendations to the Idaho Public Utilities Commission in 1992, at which time the Commission established the PCA as an annual adjustment to the Company's rates. I sponsored the Company's annual PCA adjustment in each of the years 1996 through 2003. I continue to supervise PCA-related regulatory filings.

After the conclusion of the Company's 2004 general rate case in Oregon, which was based upon a 2003 test year, I worked with the Staff of the Public Utility Commission of Oregon ("OPUC" or "Commission"), the Citizens' Utility Board ("CUB") of Oregon, and the Industrial Customers of Oregon to develop methods to annually adjust the power supply expense related portion of Oregon rates. These methods include the October update filing of normalized power supply expenses and the March filing of forecasted power supply expenses, which are used in combination to determine the Annual Power Cost Update ("APCU") rate that will go into effect the following June, and also include the February true-up or power cost adjustment mechanism ("PCAM"), which determines an amount to be added or subtracted from the queue of power supply deferrals.

In 1996, I was promoted to Director of Revenue Requirement and in 2002 I was promoted to Manager of Revenue Requirement. I have managed the preparation of revenue requirement information for regulatory proceedings in both Idaho and Oregon since 1996.

In 2008, I was promoted to Director of State Regulation. In that capacity, I was asked by Mr. Ric Gale, Vice President of Regulatory Affairs, to lead, manage, and coordinate the preparation and development of this case. I provided guidance to the various witnesses regarding the consistency of the Company's approach to preparing rate filings. I supervised and coordinated the preparation of testimony and I am the Company witness regarding regulatory policy. I have reviewed the Company proposals in this case with Mr. Gale and the Company's senior executives.

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

A. As the initial Idaho Power witness, the purpose of my testimony is to provide a general overview of the case. I will discuss the line-up of Company witnesses and briefly describe the purpose of their testimony. Included in the case overview, I will describe the growth in investment, expenses, and revenues since the Company's last general rate case. I will describe the Company's earnings performance for its Oregon jurisdiction since 2005. My testimony, along with the testimony of the remainder of Company witnesses, will demonstrate the need for an overall 22.6 percent revenue increase from the Company's Oregon jurisdictional customers.

Q. What are the regulatory policy issues related to the preparation of a general rate case?

A. The policy decisions related to the preparation of a general rate case include the selection of the test year, the timing of general rate relief requests, the treatment of annualizing adjustments, and the treatment of known and measurable adjustments.

Q. What is the Company's stated test year for determining its Oregon jurisdictional revenue requirement?

A. The Company has prepared a twelve months ending December 31, 2009, test year ("2009 Test Year" or "Test Year").

Q. Why did you choose 2009 as the Test Year?

A. In order to meet the legal requirement that rates be fair, just, reasonable, and sufficient, the Commission must establish a test year that most closely reflects the investment and expense levels that will exist at the time new rates are implemented. Historically, Idaho Power Company has proposed historical test years based upon actual data for its rate filings in both Oregon and Idaho. In recent years, for Idaho Power's Idaho filings, the Company has requested the use of forecasted test years. In 2007, the Company asked for rates in Idaho based upon a forecasted 2007 test year and likewise in 2008, the Company asked for rates in Idaho based upon a forecasted test year 2008. The purpose of the Company's requests in Idaho and its current request in Oregon is to utilize a test year that is representative of the level of the Company's investments and expenses that will exist concurrently with the resulting rates in effect. The Company believes that a 2009 test year will provide fair representation of the Company's investments and expenses that will exist at the time that new rates become effective upon completion of this case.

Q. Why are you requesting rate relief at this time?

A. There are two reasons that the Company is requesting rate relief at this time. First, as will be demonstrated by Company witnesses, there is a need to properly align Oregon revenues with Oregon allocated expenses and reasonable returns on investments. Second, the Staff requested and the Company committed to filing a general rate case prior to the end of 2009 as a condition of arriving at settlement of revised depreciation rates in Docket No. UM 1395.

Q. Based upon the order in which witnesses will testify, what is the first topic that will be presented to the Oregon Commission in this case?

A. The first topic in this case is the determination of the appropriate return on equity ("ROE") percentage to be utilized in deriving an overall rate of return that the Company is authorized to earn on its rate base. Mr. William Avera has been retained by the Company as its return on equity ROE expert. Mr. Avera also performed this function in the Company's previous Oregon rate case, as well as the last five Idaho rate cases, and has testified on the Company's behalf before the Federal Energy Regulatory Commission ("FERC"). Mr. Avera discusses risk factors relevant to Idaho Power and performs quantitative analyses of the current cost of equity to independently evaluate the appropriate ROE for the Company based upon his assessment of a reasonable ROE range for Idaho Power. In this proceeding, Mr. Avera concludes that an 11.25 percent ROE as selected by the Company represents a fair rate of return on equity.

Company witness Steven Keen, Vice President and Treasurer for Idaho Power, builds on Mr. Avera's conclusions by more specifically addressing the relevant risk factors impacting the Company. Mr. Keen discusses the factors that contributed to the Company's selection of 11.25 percent as the appropriate return on equity and demonstrates that the currently authorized ROE of 10 percent should be increased to 11.25 percent. Mr. Keen's proposed return on equity percentage and overall rate-of-return values have been incorporated in the Company's testimony addressing the determination of the Oregon jurisdictional revenue requirement.

Q. Has the Company quantified its actual return on equity for the last five years?

A. Yes, Mr. Keen will testify that over the last five years, the Company's actual ROE has been less than 9 percent on a system-wide basis. During the same period of time, the implied ROE for the Oregon jurisdiction has been less than 5 percent.

Q. What auditable information has the Company provided in this case with regard to the investments and expenses of the Company?

A. The Company has utilized actual 2008 investment and expense information as an auditable starting point for determining the 2009 Test Year. Company witness Douglas Jones, Regulatory Accounting and Support Team Leader for Idaho Power, will provide testimony regarding audited financial information, including levels of investment and expenses for the twelve-month period ending December, 31, 2008. Mr. Jones will also identify certain adjustments to operating expenses and rate base consistent with standard historical Oregon ratemaking practices.

Q. Who addresses how the actual 2008 expense and investment information was used to estimate 2009 expense and investment levels for the Test Year?

A. Company witness Catherine Miller, Director of Strategic Analysis, will describe the methods of estimating 2009 levels of investment and expenses based upon the actual 2008 levels. Ms. Miller does not address the normalization of power supply expenses

(FERC accounts 501, fuel (coal); 547, fuel, gas; 555, purchased power; and 447, opportunity sales (an offset to power supply expenses)) in her testimony.

Q. In general, how has the Company's electric plant in service changed since the last general rate case test year of 2003?

A. From 2003 through 2008, exclusive of depreciation, the Company's electric plant investment increased approximately $800 million. This increase reflects the addition of two simple-cycle gas-fired peaking plants, new construction at 21 substation sites, the addition of 1,975 pole-miles of distribution line, and capacity expansion or new construction affecting 95 pole-miles of transmission line. Today the Company's generation system has a total nameplate capacity of 3,267 megawatts compared to 2,912 megawatts at the start of 2003. Taking accumulated depreciation of electric plant investment into consideration, the Company's 2009 Test Year system rate base has increased by approximately $600 million since the last general rate case test year, 2003.

Q. What was the basis for making annualizing adjustments to rate base for 2009?

A. The annualizing adjustments to rate base for 2009 are related to electric plant in service items expected to close to plant during 2009. These items and their related impacts (such as depreciation and property tax) were treated as if they were in place for a full twelve months.

Q. Please describe the adjustments to the 2009 operating expense related to payroll.

A. The adjustments to the 2009 operating expense related to payroll are intended to result in the payroll expense structure that will be in place at the beginning of 2010.

Q. Has the Company included an adjustment to operating expense to reflect employee incentives.

A. Yes. Since the last general rate case, Idaho Power has made a material change in the manner in which it compensates its employees. Starting in 1995, the Company modified its existing "cash" compensation to include an element of "pay at risk." The new plan continues to provide a fixed-base salary, but now includes the potential for an incentive. Since the incentive can vary from year to year according to Company and employee performance, using the actual incentive amount as part of the Test Year compensation can be misleading. Because the range of potential outcomes is large, a normalized number is more reflective of ongoing compensation than an actual amount.

Q. Why do you use the term "pay at risk"?

A. Before the incentive was introduced, the Company targeted its base pay upon the 60th percentile of the relevant labor market rate for the specific job category. After the incentive was added to the compensation package, the benchmark for the base pay was reduced to the 50th percentile. The difference between the two percentile levels became the pay at risk.

Q. How much pay is currently considered at risk?

A. The Company has established a customer related target of 4 percent of employee salaries being at risk. This 4 percent target can be achieved if customer related goals relating to customer satisfaction and system reliability are met. Another 2 percent target of additional pay at risk is related to the Company's financial performance. For purposes of this case, the Company has requested inclusion of the customer satisfaction related pay at risk amounts in its revenue requirement and the exclusion of the 2 percent financial performance related to pay at risk. Incentives for executive level employees have also been excluded.

Q. Has the Company included a pending salary structure adjustment in its salary structure for ratemaking purposes?

A. Yes. The Test Year salary expense reflects a salary structure adjustment ("SSA") at year-end 2009. The anticipated SSA is 3 percent. The actual SSA will be determined by the Company's Board of Directors in either the November 2009 or January 2010 Board meeting prior to the anticipated change in Oregon rates.

Q. How have the Operating Revenues of the Company been adjusted?

A. The Operating Revenues are primarily adjusted through the normalizing adjustments to the Company's net power supply expenses as a result of the application of multiple water conditions. Other known changes to tariffs or contracts were also included either in the Test Year revenues or adjustments to the Test Year. Sales revenues for the 2009 Test Year were based on a forecast of weather normalized retail sales.

Q. You stated that Ms. Miller does not address power supply expenses in her testimony. Who is the Company witness addressing power supply expenses?

A. I instructed Company witness Scott Wright, Pricing Analyst, to prepare a 2009 Test Year look at normalized power supply expenses. Mr. Wright also prepared the April 2009 through March 2010 normalized power supply analysis that is reflected as the October portion of the current APCU rate. In his testimony, Mr. Wright will describe the current quantification of normalized power supply expenses and contrast these values to the quantification of normalized power supply expenses currently reflected in the Company's base rates plus the October portion of the APCU rate ("October Update") that became effective June 1, 2009 (Order No. 09-186, Docket No. UE-203).

Q. In general, how does Mr. Wright's current quantification of normalized power supply expenses compare to the October Update of normalized power supply expenses?

A. Mr. Wright's current quantification of normalized power supply expenses on a system basis is $205.9 million prior to Oregon specified recomputed PURPA qualifying facility ("QF") expenses. Once QF expenses are recomputed using Oregon specified rates, the total power supply expenses increase to $222.9 million on a system basis. This $222.9 million is $59.1 million higher than the October Update quantification of $163.8 million in normalized power supply expenses. Mr. Wright will discuss the major factors that drive the $59.1 million increase; however, I would also like to comment on two of the factors: (1) changes in market prices and (2) Oregon treatment of PURPA contract expenses.

Q. Please comment on how changes in market prices affect power supply expenses.

A. As I mentioned earlier in my testimony, purchased power expenses and surplus sales revenues are included in what traditionally have been referred to as power supply expenses. In the months following the preparation of the October Update of normalized power supply expenses, current and forward market prices for electricity have fallen. This reduction provides benefits to customers during periods of time when the Company is purchasing power to satisfy its load requirements, but results in increased power supply expenses during periods of time when the Company is selling surplus energy as an offset to power supply expenses. Mr. Wright testifies that the combined effect of updating power supply expenses to reflect current and forward market prices is an increase to normalized power supply expenses of $41.3 million.

Q. Please comment on Oregon treatment of PURPA QF expenses?

A. Since the signing of the first QF contract in 1982, the number of QF contracts the Company has entered into with small power producers has grown to 91. Many of those contracts have payment provisions requiring Idaho Power to pay a levelized monthly payment over the life of the contract. Oregon regulation has required Idaho Power to reflect a non-levelized payment stream in rates rather than the levelized payment stream provided for under the contract. Under a non-levelized payment stream, Oregon customers have benefitted by paying less than contract levels in the early years of the contracts. As time has passed, the non-levelized payment stream now exceeds the levelized payment stream and, as a result, Oregon customers are responsible for paying for amounts greater than would be paid under a levelized payment stream. Mr. Wright tells me that the additional Oregon responsibility for PURPA payments was not reflected in the Company's October Update and, as a result, the Company is not currently recovering amounts to which it is entitled. Such amounts, however, will be captured in PCAM deferrals. Based upon PCAM methodology, the Company will be allowed to recover only 90 percent of the non-included, re-priced differential from the October update subject to an earnings test for 2009. The Company discovered that it had not re-priced PURPA payments in the October Update and notified the Staff during Staff review of the filing, but did not request an adjustment to the Company's filing. Mr. Wright tells me that a re-pricing adjustment for PURPA project costs would increase system power supply costs by over $17 million.

Q. Based upon your review of Mr. Wright's computations of normalized Test Year power supply expenses, what instructions did you give to Mr. Wright?

A. While it is important to the Company to have properly reflected normalized power supply expenses included in its base rates over time, the Company is willing to wait until its next October Update to adjust normalized power supply expenses. The previously noted increases to rate base, combined with the Company's request to increase its return on equity percentage along with the growth of expenses over time, amount to a sizeable increase to Oregon customers even without a normalized power supply expense update at this time. For this reason, I instructed Mr. Wright to provide 2009 Test Year power supply expenses for informational purposes only. For purposes of determining the Company's Oregon jurisdictional revenue requirement, the 2008 October Update of normalized power supply expenses has been utilized.

Q. Who is the Company witness that incorporated Mr. Keen's return on equity recommendations, Ms. Miller's test year investment and expense information, and Mr. Wright's October 2008 Update of normalized power supply expenses into the

Company jurisdictional separation study to arrive at the Oregon jurisdictional revenue requirement and Oregon jurisdictional revenue deficiency determination?

A. Company witness Jeannette Bowman, Senior Pricing Analyst, performed the Oregon jurisdictional revenue requirement computations. Ms. Bowman's study demonstrates that even without an update to normalized power supply expenses, the revenue deficiency of approximately $7.3 million amounts to a need for Oregon jurisdictional sales and wheeling revenue to increase by 22.6 percent in order for the Company to recover its Oregon jurisdictional revenue requirement of $39.8 million.

Q. Please identify the major drivers of the need for a 22.6 percent, $7.3 million, increase in Oregon jurisdictional revenues?

A. As I noted earlier in my testimony, since the last test year, 2003, Company investments have added approximately $800 million to plant in service for the benefit of Idaho Power customers. Taking accumulated depreciation into effect, net additions to rate base since 2003 have been approximately $600 million. Without a change in the currently authorized return on equity percentage of 10 percent, the Company should be allowed to recover an additional $3.7 million, an 11.5 percent increase in Oregon jurisdictional revenues related solely to new Oregon jurisdictional rate base.

In addition to growth in rate base, Mr. Keen's recommendation for an increase in the authorized rate of return on equity suggests that the Company is entitled to additional return dollars amounting to $1.5 million, a 4.8 percent increase in Oregon jurisdictional revenues.

The final major driver of the need for a 22.6 percent increase in Oregon jurisdictional revenues is the difference between growth in Oregon jurisdictional expenses excluding power supply expenses and growth in Oregon jurisdictional revenues since the last test year, 2003. Growth in expenses has outpaced growth in revenues over the last 6 years by $2.1 million, thus creating the need for an additional 6.3 percent increase in Oregon jurisdictional revenues.

Summing the three major drivers of the case results in the need for an increase in Oregon jurisdictional revenues of $7.3 million ($3.7 + $1.5 + $2.1), which equates to a 22.6 percent increase (11.5%+ 4.8%+ 6.3%).

Q. How does the requested Oregon rate increase of 22.6 percent compare to the rate increases that have occurred in the Company's Idaho jurisdiction over the past five years?

A. Over the past five years, the Company's Idaho customers have experienced base rate increases of approximately 21.5 percent. These increases are largely the result of three general rate cases and two separate trackers for major plant additions. Idaho customers received base rate increases from general rate cases in 2006, 2008, and 2009 of 3.2 percent, 5.2 percent, and 4.0 percent, respectively. Base rates increased for Idaho customers in 2005 by 1.8 percent with the addition of the Bennett Mountain simple-cycle gas plant and again in 2008 by 1.4 percent when the Danskin 1 simple-cycle gas plant was added to the Company's rate base. In addition, Idaho customers have also experienced rate increases related to the Energy Efficiency Rider (currently 4.75 percent of base revenue), the annual PCA, the inclusion of Advanced Metering Infrastructure investment into rate base, and the annual Fixed-Cost Adjustment.

Q. Who is the Company witness that describes how the Oregon jurisdictional revenue requirement should be spread to the various classes of customers?

A. Company witness Timothy Tatum, Manager of Cost of Service, describes the spread of the Oregon jurisdictional revenue requirement to customer classes. Mr. Tatum begins by identifying that portion of the Oregon jurisdictional revenue requirement that is associated with either the production, transmission, or distribution function. He then further separates the functional portions of the revenue requirement into energy, demand, or customer classifications. He then uses marginal cost determinations to weight the distribution of the functionalized and classified revenue requirement amounts to customer classes. Based upon this method of distribution of Oregon jurisdictional revenue requirement to classes (often referred to as class cost-of-service), individual classes would experience percentage changes in their revenue requirements that differ from the jurisdictional need for a 22.6 percent increase.

Q. Did Mr. Tatum consider the impacts on the various classes of customers if all classes of customers were moved to full cost-of-service?

A. Yes. Based upon Mr. Tatum's analyses, Irrigation customers would experience a 93 percent increase in their rates if moved to full cost-of-service. Large Power Service customers receiving power at transmission level voltage would see an 11 percent rate decrease if moved to full cost-of-service.

Q. What direction did you give to Mr. Tatum with regard to establishing target revenue requirements by class prior to rate design?

A. In order to avoid imposing a 93 percent increase on Irrigation customers, I instructed Mr. Tatum to move the Irrigation class and the Traffic Control class to 75 percent of their cost-of-service. Such a move still results in a 45 percent increase in Irrigation rates. I also instructed Mr. Tatum not to reduce the rates for any class of customer. As a result, the Large Power Service customers receiving power at transmission voltage will continue to pay above their class cost-of-service. I instructed Mr. Tatum to spread the remaining revenue requirement to customer classes in a manner such that the classes would all be paying the same percentage above their cost-of-service. That percentage above cost-of-service turned out to be 3.1 percent.

Q. Who was responsible for coordinating the Company's rate design proposals in this Case?

A. Company witness Michael Youngblood, Manager of Rate Design, was responsible for coordinating the Company's rate design proposals in this case.

Q. Did you and Mr. Youngblood discuss any goals to be achieved through rate design?

A. Yes. Mr. Youngblood and I identified three general goals which Mr. Youngblood then conveyed to the rate design witnesses. The three goals are to: (1) establish prices which primarily reflect the costs of the services provided, (2) have cost-based rate proposals designed to align with and encourage energy efficiency, and (3) provide consistency and continuity throughout the Company's service territory.

Q. Please identify the witnesses who took Mr. Tatum's class revenue targets and Mr. Youngblood's stated goals to arrive at the Company's proposed rate design.

A. Company witness Courtney Waites, Pricing Analyst, was responsible for Residential rate design. Company witness Darlene Nemnich, Senior Pricing Analyst, is the Company witness addressing rate design for the Small General Service, General Service, and Large Power Service customers. Company witness Scott Sparks, Senior Pricing Analyst, is the Company witness addressing Irrigation customer rate design as well as rate design for the remaining customer classes. These witnesses present the Company's proposal for rate design and discuss how the proposed rates achieve the goals as stated by Mr. Youngblood.

Q. Please define "rate spread."

A. Rate spread is a term that refers to the division of the jurisdictional revenue requirement into individual revenue requirements for each customer class.

Q. What is the Company's philosophy on establishing rate spread among the customer classes?

A. In the last several general rate cases, the Company's primary approach to ratemaking has been to reflect costs as accurately as possible when setting its tariff rates. Accordingly, the Company's ratemaking proposals usually advocate movement toward cost-of-service results which assign costs to those customers that cause the Company to incur the costs. A parallel and complementary goal is to set rates that encourage the efficient use of Idaho Power's product. The Company realizes that there are other ratemaking objectives, such as ability to pay, that the Commission may consider in making its determination. However, the Company believes that the best starting point for Commission deliberations is an economic one. Due to the magnitude of change that would occur for some classes if moved to full cost-of-service, the Company has mitigated the impact by proposing movement toward cost-of-service, but not a movement to full cost-of-service for classes. As a result, some classes will pay above their cost-of-service while others will pay below their cost-of-service.

Q. Has the Company's cost-based approach to revenue requirement influenced rate design proposals?

A. Yes, the cost-based approach has led to rate design proposals that better align fixed costs with fixed prices and variable costs with variable prices. Ideally, an energy rate that corresponds to energy costs would help address a number of rate-related issues, including net metering and customer conservation decisions. The emphasis on moving fixed and variable prices to be more reflective of fixed and variable costs has led to the Company's proposals to increase the monthly service charge for all customers taking metered service and to place more emphasis on the demand charge for those customers taking demand-metered service. Since residential and commercial customers are not demand metered, the service charge is the only fixed rate component available to adjust and thus is more important as a tool for fixed cost recovery. The increases to the service charges are a moderate step toward better alignment of costs and prices.

Q. Did the Company's cost-based approach influence any other ratemaking proposals?

A. Yes, the cost-based approach also influenced the decision to propose seasonal and time-of-use rates for certain customer groups. Both types of time-based rates allow for the incorporation of time-based cost differences into the Company's pricing.

Q. Who is the final Company witness?

A. Mr. Youngblood, who I have previously identified, is the final Company witness. He will discuss the consistency of the various rate proposals for the customer classes, address proposed changes to administrative rules and other miscellaneous issues, and will provide a summary of the revenue impacts of the Company's proposed rates on each of the Company's Oregon retail rate classes.

Q. Please describe the Company's last general rate increase in Oregon.

A. The Company's last general rate case, Docket No. UE 167, concluded on July 28, 2005, when the Commission issued Order No. 05-871 allowing Idaho Power to increase its rates by $596,973, or 2.37 percent. Permanent rates were implemented on August 8, 2005. The majority of issues in that case were resolved by stipulation. The one issue that was not agreed to in the stipulation was the appropriate level of normalized power supply expenses. The Commission Order reduced the Company requested level of normalized power supply expenses by over $50 million.

Q. What changes in rates associated with power supply expenses have occurred since the last general rate case?

A. Since the last general rate case the Company has worked with Commission Staff and the Citizens' Utility Board of Oregon to develop a power cost adjustment methodology that allows for an annual update of normalized power supply expenses, a forecast of anticipated deviations from the normalized base, and a true-up of deviations from the previous year's forecast of power supply expenses. That methodology was approved for ratemaking by the Commission in Order No. 08-238 issued on April 28, 2008. Prior to approval of the power cost adjustment methodology, the Company requested and was allowed to defer excess power supply expenses in 2006, 2007, and 2008. Due to statutory restrictions on the recovery of deferrals, none of these deferred amounts have been fully amortized at the time of this filing.

Q. Earlier in your testimony you have mentioned three general rate cases (2005, 2007, and 2008) and two single-issue rate tracker cases (2005 and 2008) that have occurred in Idaho since the completion of the last Oregon general rate case. Why has the Company not made similar filings in Oregon?

A. Idaho Power was deeply concerned about the treatment of power supply expenses in the last Oregon general rate case and for that reason focused its efforts on resolving the power supply expense issue. The Company first moved for reconsideration of the Commission's decision, and then appealed the Commission decision to the Circuit Court. After those efforts failed, the Company worked diligently to resolve power supply issues though its power cost adjustment mechanism proposal and settlement discussions with Staff and Intervenors. With the implementation of the APCU and the PCAM, Oregon customers have seen rate increases associated with power supply expenses. However, Oregon customers have not experienced rate adjustments associated with non-power supply expense growth or growth in rate base required to serve growing loads. As a result, Oregon customers have been insulated from general rate increases while the Company concentrated on power supply expense recovery. While the Company regrets the impact that delayed recovery of growing expenses will now have on customers at this time, it is important to recognize that Oregon customers have not been paying for their true cost-of-service over the last 6 years.

Q. Did the Company consider proposing any mitigation to the overall 22.6 percent increase to Oregon customers?

A. Yes. The Company considered proposing a phase-in of the 22.6 percent increase over a two-year period of time; however, the Company concluded that any deferral of revenue collection would be subject to the same rules associated with the deferral of power supply expenses. As a result, any deferral of recovery in this case would be placed in the deferral queue and would not be recoverable until far in the future. Based upon this conclusion, the Company feels obligated to request the full 22.6 percent increase at this time.

Q. Do you believe that the Company's proposed rates will be fair, just, and reasonable to the Company and its Oregon customers?

A. Yes.

Q. Does this 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 INCREASE ITS RATES	)
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SERVICE IN THE STATE OF OREGON.	)
	)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

WILLIAM E. AVERA

July 31, 2009

Q. Please state your name and business address.

A. William E. Avera, 3907 Red River, Austin, Texas, 78751.

Q. In what capacity are you employed?

A. I am the President of FINCAP, Inc., a firm providing financial, economic, and policy consulting services to business and government.

Q. Please describe your educational background and professional experience.

A. A description of my background and qualifications, including a resume containing the details of my experience, is attached as Exhibit No. 201.

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

A. The purpose of my testimony is to present to the Public Utility Commission of Oregon ("OPUC") my independent evaluation of the 11.25 percent fair rate of return on equity ("ROE") requested by Idaho Power Company ("Idaho Power" or "the Company") for its jurisdictional utility operations.

Q. Please summarize the basis of your knowledge and conclusions concerning the issues to which you are testifying in this case.

A. As is common and generally accepted in my field of expertise, I have accessed and used information from a variety of sources. I am familiar with the organization, finances, and operations of Idaho Power from my participation in prior proceedings before the OPUC and the Idaho Public Utilities Commission ("IPUC"). In connection with the present filing, I considered and relied upon corporate disclosures and management discussions, publicly available financial reports and filings, and other published information relating to Idaho Power. I also reviewed information relating generally to current capital market conditions and specifically to current investor perceptions, requirements, and expectations for Idaho Power's utility operations. These sources, coupled with my experience in the fields of finance and utility regulation, have provided me with a working knowledge of the issues relevant to investors' required return for Idaho Power, and they form the basis of my analyses and conclusions.

Q. How did you evaluate the reasonableness of Idaho Power's requested ROE?

A. My evaluation of Idaho Power's requested ROE was based in part on analyses conducted on behalf of the Company before the Idaho Public Utilities Commission in Case No. IPC-E-08-10, with the details being presented in my direct testimony ("Idaho Testimony") included as Exhibit No. 206. As discussed there, I recommended that Idaho Power be authorized a fair rate of return on equity in the 10.8 percent to 11.8 percent range, with a ROE of 11.25 percent falling slightly below the midpoint of this range.

In addition to the research and analyses contained in my Idaho Testimony, I examined changes in capital market conditions since that time and developed updated quantitative analyses to estimate the current cost of equity. These included application of the discounted cash flow ("DCF"), Capital Asset Pricing Model ("CAPM"), and comparable earnings methodologies, which are more fully described in Exhibit No. 206.

Q. What is the role of ROE in setting a utility's rates?

A. The rate of return on common equity compensates shareholders for the use of their capital to finance the plant and equipment necessary to provide utility service. Investors commit capital only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks. To be consistent with sound regulatory economics and the standards set forth by the Supreme Court in the *Bluefield*[1] and *Hope*[2] cases, a utility's allowed return on common equity should be sufficient to: (1) fairly compensate capital invested in the utility, (2) enable

[1] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.W. 679 (1923).

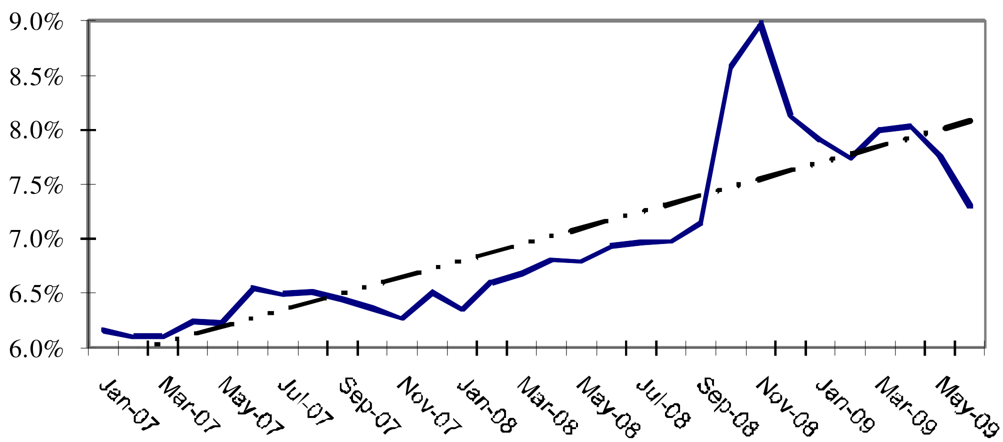
[2] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

the utility to offer a return adequate to attract new capital on reasonable terms, and (3) maintain the utility's financial integrity.

Q. What are the implications of recent capital market conditions?

A. Since the time that the analyses contained in my Idaho Testimony were prepared, the financial markets and the economy have endured uncertainties that are unprecedented in recent history. The tumultuous conditions in the capital markets that began in the third quarter of 2008 have evidenced an upward shift in the returns investors require to bear risk. This has been reflected in higher yields on utility bonds, which have been especially pronounced for companies in the triple-B rating category. Figure 1 plots the monthly average yield on triple-B rated public utility bonds reported by Moody's Investors Service ("Moody's") from January 2007 through June 2009:

FIGURE 1
MOODY'S TRIPLE-B PUBLIC UTILITY BOND YIELD
(JANUARY 2007 – JUNE 2009)



As illustrated above, an upward trajectory for the yields on triple-B rated public utility debt has been evident, with the average yield of 7.3 percent in May 2009 being approximately 40 basis points higher than the 6.9 percent benchmark cited in my Idaho Testimony.

Similarly, the precipitous drop in stock prices also reflects a significant reappraisal of risks and future expectations on the part of investors. With respect to utilities specifically, as of June 30, 2009, the Dow Jones Utility Average stock index was approximately 30 percent below the level of a year earlier. While the degree of capital market volatility certainly complicates any assessment of future trends, the preponderance of the evidence from the investment community favors a view that the current economic malaise is not destined for a quick recovery and that investors' required returns on long-term capital are likely to remain elevated. Taken together, this evidence indicates that investors' required rate of return has increased since my Idaho Testimony was prepared.

Q. What other factors are relevant in evaluating Idaho Power's requested ROE?

A. Apart from the upward shift in investors' required rates of return generally, it is also important to recognize that the investment risks specific to Idaho Power have increased. Based in large part on concerns stemming from the outcome of Idaho Power's past rate proceedings and the pressures of ongoing capital requirements, Standard & Poor's Corporation ("S&P") lowered Idaho Power's corporate credit rating from "A-" to "BBB+" in November 2004.[3] Since the Company's last General Rate Case filing before the OPUC, S&P again lowered the Company's corporate credit rating from "BBB+" to "BBB" in January 2008,[4] with Moody's revising its rating outlook for Idaho Power to "negative" in June 2008, warning investors of the potential for deterioration in the Company's credit standing going forward.[5]

[3] Standard & Poor's Corporation, "IDACORP and Unit Ratings Lowered, Removed From CreditWatch Negative," *RatingsDirect* (Nov. 29, 2004).

[4] Standard & Poor's Corporation, "IDACORP, Idaho Power Co. Ratings Lowered One Notch To 'BBB'; Outlook Stable," *RatingsDirect* (Jan. 31, 2008).

[5] Moody's Investors Service, "Rating Action: Idaho Power Company," *Global Credit Research* (June 3, 2008).

Q. What does the decline in Idaho Power's credit rating imply with respect to a fair ROE for its jurisdictional utility operations?

A. Although rates of return on equity cannot be directly observed, the observed yields on long-term bonds provide direct evidence of the additional return that investors require in return for bearing the risks associated with weaker credit ratings. Moody's recently reported an average yield on single-A rated public utility bonds for June 2009 of 6.2 percent, versus an average yield of 7.3 percent for bonds rated triple-B. Based on this evidence, the debt markets now require approximately 110 basis points in additional return in order to compensate for the greater risks associated with Idaho Power's current triple-B rating. Equity investors would undoubtedly require a significantly greater premium for bearing the higher risk associated with the more junior common stock of a utility with a triple-B rated company, versus one that is rated single-A. Thus, the decline in Idaho Power's bond rating also indicates that investors' required rate of return has increased.

Q. What other evidence confirms your conclusion that Idaho Power's requested ROE is reasonable?

A. In order to further confirm my conclusion that an ROE of 11.25 percent continues to be reasonable for Idaho Power, I updated the DCF methodology that was applied in the Idaho Testimony. This analysis focused on the same proxy group of electric utilities, with the exception of two companies (Empire District Electric Company and Hawaiian Industries, Inc.) that were eliminated because The Value Line Investment Survey ("Value Line") expects that they will cut their common dividend payments. The criteria used to develop this proxy group reflect objective, published indicators that incorporate consideration of a broad spectrum of risks, including financial and business position, relative size, and exposure to company specific factors. As a result, investors are likely to regard this group as having risks and prospects comparable to Idaho Power.

Q. What were the results of your updated DCF analysis?

A. The results of my updated DCF analysis are presented in Exhibit No. 202, which contains the projected IBES earnings growth rates compiled and reported Thomson Reuters for each of the firms in the reference group of electric utilities. Also presented are the earnings growth projections reported by Value Line and Zacks Investment Research.

Because conventional applications of the constant growth DCF model often examine the relationships between retained earnings and earned rates of return as an indication of the growth investors might expect from the reinvestment of earnings within a firm, the sustainable "b x r" growth rate of the DCF model was calculated for each firm in the electric utility reference group based on projected data from Value Line. The expected retention ratio (b) was calculated based on projected data for dividends and earnings per share and each firm's expected earned rate of return (r) was computed by dividing projected earnings per share by the corresponding projections of net book value. The resulting sustainable growth rate for each electric utility is shown in Exhibit No. 203.

As shown on Exhibit No. 202, after eliminating illogical cost of equity estimates in a manner consistent with that described in my Idaho Testimony,[6] my updated DCF analyses resulted in average cost of equity estimates ranging from 11.1 percent to 12.1 percent, with the average of the proxy group estimates being 11.6 percent.

Q. What other analyses did you conduct to confirm your conclusion that an 11.25 percent ROE remains reasonable for Idaho Power?

A. In addition to the DCF model, I also updated the results of the forward-looking application of the CAPM discussed in my Idaho Testimony. As shown in Exhibit No. 204, this CAPM approach, which is identical to that contained in my Idaho Testimony but updated to reflect more current information, implied cost of equity estimates for the firms in the proxy

[6] My evaluation of low-end estimates excluded values that were less than 100 basis points above the 7.3 percent average yield on triple-B utility bonds for June 2009 reported by Moody's Investors Service.

group ranging from 9.9 percent to 13.5 percent, with the average being 11.2 percent. With respect to comparable rates of return for electric utilities, the most recent Value Line reports that its analysts anticipate an average earned rate of return on common equity for the electric utility industry of 10.5 percent in 2009, 11.0 percent in 2010, and 11.5 percent over its three-to-five year forecast horizon.[7] Consistent with the methodology presented in my Idaho Testimony, the returns on common equity projected by Value Line over its three-to-five year forecast horizon for the utilities in the proxy group are shown on Exhibit No. 205. As shown there, after eliminating extreme outliers, Value Line's projections suggested an average ROE of 11.3 percent.

Q. Please summarize your findings regarding the fair rate of return on equity for Idaho Power.

A. Based on the capital market research discussed above and in my Idaho Testimony, it is my conclusion that an ROE of 11.25 continues to represent a conservative estimate of investors' required rate of return for Idaho Power in today's capital markets. In evaluating the rate of return for Idaho Power, it is important to consider investors' continued focus on the unsettled conditions in restructured wholesale energy markets, the Company's ongoing exposure to these markets to meet a portion of its energy supply, as well as other risks associated with the utility industry, such as heightened exposure to regulatory uncertainties. My conclusion is further supported by the fact that the "bare-bones" cost of equity estimates discussed above do not reflect the impact of issuance costs, with a flotation cost adjustment being properly considered in establishing an allowed ROE for Idaho Power. Considering capital market expectations, the potential uncertainties faced by Idaho Power, the Company's unique exposure to fluctuations in hydroelectric generation, and the economic requirements necessary to maintain financial integrity and support additional

[7] The Value Line Investment Survey at 687 (June 26, 2009).

capital investment even under adverse circumstances, it is my opinion that an ROE of 11.25 percent is reasonable at this critical juncture.

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

A. Yes, it does.

Idaho Power/201
Witness: William E. Avera

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of William E. Avera
Background and Qualifications

July 31, 2009

QUALIFICATIONS OF WILLIAM E. AVERA

Q. What is the purpose of this exhibit?

A. This exhibit describes my background and experience and contains the details of my qualifications.

Q. What are your qualifications?

A. I received a B.A. degree with a major in economics from Emory University. After serving in the U.S. Navy, I entered the doctoral program in economics at the University of North Carolina at Chapel Hill. Upon receiving my Ph.D., I joined the faculty at the University of North Carolina and taught finance in the Graduate School of Business. I subsequently accepted a position at the University of Texas at Austin where I taught courses in financial management and investment analysis. I then went to work for International Paper Company in New York City as Manager of Financial Education, a position in which I had responsibility for all corporate education programs in finance, accounting, and economics.

In 1977, I joined the staff of the Public Utility Commission of Texas ("PUCT") as Director of the Economic Research Division. During my tenure at the PUCT, I managed a division responsible for financial analysis, cost allocation and rate design, economic and financial research, and data processing systems, and I testified in cases on a variety of financial and economic issues. Since leaving the PUCT, I have been engaged as a consultant. I have participated in a wide range of assignments involving utility-related matters on behalf of utilities, industrial customers, municipalities, and regulatory commissions. I have previously testified before the Federal Energy Regulatory Commission, as well as the Federal Communications Commission, the Surface Transportation Board (and its predecessor, the Interstate Commerce Commission), the Canadian Radio-Television and Telecommunications Commission, and regulatory agencies, courts, and legislative committees in over 40 states.

In 1995, I was appointed by the PUCT to the Synchronous Interconnection Committee to advise the Texas legislature on the costs and benefits of connecting Texas to the national electric transmission grid. In addition, I served as an outside director of Georgia System Operations Corporation, the system operator for electric cooperatives in Georgia.

I have served as Lecturer in the Finance Department at the University of Texas at Austin and taught in the evening graduate program at St. Edward's University for twenty years. In addition, I have lectured on economic and regulatory topics in programs sponsored by universities and industry groups. I have taught in hundreds of educational programs for financial analysts in programs sponsored by the Association for Investment Management and Research, the Financial Analysts Review, and local financial analysts societies. These programs have been presented in Asia, Europe, and North America, including the Financial Analysts Seminar at Northwestern University. I hold the Chartered Financial Analyst (CFA®) designation and have served as Vice President for Membership of the Financial Management Association. I have also served on the Board of Directors of the North Carolina Society of Financial Analysts. I was elected Vice Chairman of the National Association of Regulatory Commissioners ("NARUC") Subcommittee on Economics and appointed to NARUC's Technical Subcommittee on the National Energy Act. I have also served as an officer of various other professional organizations and societies. A resume containing the details of my experience and qualifications is attached.

WILLIAM E. AVERA

FINCAP, INC.
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Economic and Financial Counsel

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Summary of Qualifications

Ph.D. in economics and finance; Chartered Financial Analyst (CFA ®) designation; extensive expert witness testimony before courts, alternative dispute resolution panels, regulatory agencies and legislative committees; lectured in executive education programs around the world on ethics, investment analysis, and regulation; undergraduate and graduate teaching in business and economics; appointed to leadership positions in government, industry, academia, and the military.

Employment

Principal, FINCAP, Inc. (Sep. 1979 to present)	Financial, economic and policy consulting to business and government. Perform business and public policy research, cost/benefit analyses and financial modeling, valuation of businesses (over 150 entities valued), estimation of damages, statistical and industry studies. Provide strategy advice and educational services in public and private sectors, and serve as expert witness before regulatory agencies, legislative committees, arbitration panels, and courts.
Director, Economic Research Division, Public Utility Commission of Texas (Dec. 1977 to Aug. 1979)	Responsible for research and testimony preparation on rate of return, rate structure, and econometric analysis dealing with energy, telecommunications, water and sewer utilities. Testified in major rate cases and appeared before legislative committees and served as Chief Economist for agency. Administered state and federal grant funds. Communicated frequently with political leaders and representatives from consumer groups, media, and investment community.
Manager, Financial Education, International Paper Company New York City (Feb. 1977 to Nov. 1977)	Directed corporate education programs in accounting, finance, and economics. Developed course materials, recruited and trained instructors, liaison within the company and with academic institutions. Prepared operating budget and designed financial controls for corporate professional development program.

Lecturer in Finance,
The University of Texas at Austin
(Sep. 1979 to May 1981)
Assistant Professor of Finance,
(Sep. 1975 to May 1977)

Taught graduate and undergraduate courses in financial management and investment theory. Conducted research in business and public policy. Named Outstanding Graduate Business Professor and received various administrative appointments.

Assistant Professor of Business,
University of North Carolina at Chapel Hill
(Sep. 1972 to Jul. 1975)

Taught in BBA, MBA, and Ph.D. programs. Created project course in finance, Financial Management for Women, and participated in developing Small Business Management sequence. Organized the North Carolina Institute for Investment Research, a group of financial institutions that supported academic research. Faculty advisor to the Media Board, which funds student publications and broadcast stations.

Education

Ph.D., Economics and Finance,
University of North Carolina at Chapel Hill
(Jan. 1969 to Aug. 1972)

Elective courses included financial management, public finance, monetary theory, and econometrics. Awarded the Stonier Fellowship by the American Bankers' Association and University Teaching Fellowship. Taught statistics, macroeconomics, and microeconomics.

Dissertation: *The Geometric Mean Strategy as a Theory of Multiperiod Portfolio Choice*

B.A., Economics,
Emory University, Atlanta, Georgia
(Sep. 1961 to Jun. 1965)

Active in extracurricular activities, President of the Barkley Forum (debate team), Emory Religious Association, and Delta Tau Delta chapter. Individual awards and team championships at national collegiate debate tournaments.

Professional Associations

Received Chartered Financial Analyst (CFA) designation in 1977; Vice President for Membership, Financial Management Association; President, Austin Chapter of Planning Executives Institute; Board of Directors, North Carolina Society of Financial Analysts; Candidate Curriculum Committee, Association for Investment Management and Research; Executive Committee of Southern Finance Association; Vice Chair, Staff Subcommittee on Economics and National Association of Regulatory Utility Commissioners (NARUC); Appointed to NARUC Technical Subcommittee on the National Energy Act.

Teaching in Executive Education Programs

University-Sponsored Programs: Central Michigan University, Duke University, Louisiana State University, National Defense University, National University of Singapore, Texas A&M University, University of Kansas, University of North Carolina, University of Texas.

Business and Government-Sponsored Programs: Advanced Seminar on Earnings Regulation, American Public Welfare Association, Association for Investment Management and Research, Congressional Fellows

Program, Cost of Capital Workshop, Electricity Consumers Resource Council, Financial Analysts Association of Indonesia, Financial Analysts Review, Financial Analysts Seminar at Northwestern University, Governor's Executive Development Program of Texas, Louisiana Association of Business and Industry, National Association of Purchasing Management, National Association of Tire Dealers, Planning Executives Institute, School of Banking of the South, State of Wisconsin Investment Board, Stock Exchange of Thailand, Texas Association of State Sponsored Computer Centers, Texas Bankers' Association, Texas Bar Association, Texas Savings and Loan League, Texas Society of CPAs, Tokyo Association of Foreign Banks, Union Bank of Switzerland, U.S. Department of State, U.S. Navy, U.S. Veterans Administration, in addition to Texas state agencies and major corporations.

Presented papers for Mills B. Lane Lecture Series at the University of Georgia and Heubner Lectures at the University of Pennsylvania. Taught graduate courses in finance and economics in evening program at St. Edward's University in Austin from January 1979 through 1998.

Expert Witness Testimony

Testified in over 280 cases before regulatory agencies addressing cost of capital, regulatory policy, rate design, and other economic and financial issues.

Federal Agencies: Federal Communications Commission, Federal Energy Regulatory Commission, Surface Transportation Board, Interstate Commerce Commission, and the Canadian Radio-Television and Telecommunications Commission.

State Regulatory Agencies: Alaska, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Idaho, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Missouri, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Virginia, Washington, West Virginia, Wisconsin, and Wyoming.

Testified in 42 cases before federal and state courts, arbitration panels, and alternative dispute tribunals (86 depositions given) regarding damages, valuation, antitrust liability, fiduciary duties, and other economic and financial issues.

Board Positions and Other Professional Activities

Audit Committee and Outside Director, Georgia System Operations Corporation (electric system operator for member-owned electric cooperatives in Georgia); Chairman, Board of Print Depot, Inc. and FINCAP, Inc.; Co-chair, Synchronous Interconnection Committee, appointed by Public Utility Commission of Texas and approved by governor; Appointed by Hays County Commission to Citizens Advisory Committee of Habitat Conservation Plan, Operator of AAA Ranch, a certified organic producer of agricultural products; Appointed to Organic Livestock Advisory Committee by Texas Agricultural Commissioner Susan Combs; Appointed by Texas Railroad Commissioners to study group for *The UP/SP Merger: An Assessment of the Impacts on the State of Texas;* Appointed by Hawaii Public Utilities Commission to team reviewing affiliate relationships of Hawaiian Electric Industries; Chairman, Energy Task Force, Greater Austin-San Antonio Corridor Council; Consultant to Public Utility Commission of Texas on cogeneration policy and other matters; Consultant to Public Service Commission of New Mexico on cogeneration policy; Evaluator of Energy Research Grant Proposals for Texas Higher Education Coordinating Board.

Community Activities

Board Member, Sustainable Food Center; Chair, Board of Deacons, Finance Committee, and Elder, Central Presbyterian Church of Austin; Founding Member, Orange-Chatham County (N.C.) Legal Aid Screening Committee.

Military

Captain, U.S. Naval Reserve (retired after 28 years service); Commanding Officer, Naval Special Warfare Engineering Support Unit; Officer-in-charge of SWIFT patrol boat in Vietnam; Enlisted service as weather analyst (advanced to second class petty officer).

Bibliography

Monographs

Ethics and the Investment Professional (video, workbook, and instructor's guide) and *Ethics Challenge Today* (video), Association for Investment Management and Research (1995)

"Definition of Industry Ethics and Development of a Code" and "Applying Ethics in the Real World," in *Good Ethics: The Essential Element of a Firm's Success*, Association for Investment Management and Research (1994)

"On the Use of Security Analysts' Growth Projections in the DCF Model," with Bruce H. Fairchild in *Earnings Regulation Under Inflation*, J. R. Foster and S. R. Holmberg, eds. Institute for Study of Regulation (1982)

An Examination of the Concept of Using Relative Customer Class Risk to Set Target Rates of Return in Electric Cost-of-Service Studies, with Bruce H. Fairchild, Electricity Consumers Resource Council (ELCON) (1981); portions reprinted in *Public Utilities Fortnightly* (Nov. 11, 1982)

"Usefulness of Current Values to Investors and Creditors," *Research Study on Current-Value Accounting Measurements and Utility*, George M. Scott, ed., Touche Ross Foundation (1978)

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Investment Companies: Analysis of Current Operations and Future Prospects, with J. Finley Lee and Glenn L. Wood, American College of Life Underwriters (1975)

Articles

"Should Analysts Own the Stocks they Cover?" *The Financial Journalist*, (March 2002)

"Liquidity, Exchange Listing, and Common Stock Performance," with John C. Groth and Kerry Cooper, *Journal of Economics and Business* (Spring 1985); reprinted by National Association of Security Dealers

"The Energy Crisis and the Homeowner: The Grief Process," *Texas Business Review* (Jan.–Feb. 1980); reprinted in *The Energy Picture: Problems and Prospects*, J. E. Pluta, ed., Bureau of Business Research (1980)

"Use of IFPS at the Public Utility Commission of Texas," *Proceedings of the IFPS Users Group Annual Meeting* (1979)

"Production Capacity Allocation: Conversion, CWIP, and One-Armed Economics," *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"Some Thoughts on the Rate of Return to Public Utility Companies," with Bruce H. Fairchild in *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"A New Capital Budgeting Measure: The Integration of Time, Liquidity, and Uncertainty," with David Cordell in *Proceedings of the Southwestern Finance Association* (1977)

"Usefulness of Current Values to Investors and Creditors," in *Inflation Accounting/Indexing and Stock Behavior* (1977)

"Consumer Expectations and the Economy," *Texas Business Review* (Nov. 1976)

"Portfolio Performance Evaluation and Long-run Capital Growth," with Henry A. Latané in *Proceedings of the Eastern Finance Association* (1973)

Book reviews in *Journal of Finance* and *Financial Review*. Abstracts for *CFA Digest*. Articles in *Carolina Financial Times*.

Selected Papers and Presentations

"The Who, What, When, How, and Why of Ethics", San Antonio Financial Analysts Society (Jan. 16, 2002). Similar presentation given to the Austin Society of Financial Analysts (Jan. 17, 2002)

"Ethics for Financial Analysts," Sponsored by Canadian Council of Financial Analysts: delivered in Calgary, Edmonton, Regina, and Winnipeg, June 1997. Similar presentations given to Austin Society of Financial Analysts (Mar. 1994), San Antonio Society of Financial Analysts (Nov. 1985), and St. Louis Society of Financial Analysts (Feb. 1986)

"Cost of Capital for Multi-Divisional Corporations," Financial Management Association, New Orleans, Louisiana (Oct. 1996)

"Ethics and the Treasury Function," Government Treasurers Organization of Texas, Corpus Christi, Texas (Jun. 1996)

"A Cooperative Future," Iowa Association of Electric Cooperatives, Des Moines (December 1995). Similar presentations given to National G & T Conference, Irving, Texas (June 1995), Kentucky Association of Electric Cooperatives Annual Meeting, Louisville (Nov. 1994), Virginia, Maryland, and Delaware Association of Electric Cooperatives Annual Meeting, Richmond (July 1994), and Carolina Electric Cooperatives Annual Meeting, Raleigh (Mar. 1994)

"Information Superhighway Warnings: Speed Bumps on Wall Street and Detours from the Economy," Texas Society of Certified Public Accountants Natural Gas, Telecommunications and Electric Industries Conference, Austin (Apr. 1995)

"Economic/Wall Street Outlook," Carolinas Council of the Institute of Management Accountants, Myrtle Beach, South Carolina (May 1994). Similar presentation given to Bell Operating Company Accounting Witness Conference, Santa Fe, New Mexico (Apr. 1993)

"Regulatory Developments in Telecommunications," Regional Holding Company Financial and Accounting Conference, San Antonio (Sep. 1993)

"Estimating the Cost of Capital During the 1990s: Issues and Directions," The National Society of Rate of Return Analysts, Washington, D.C. (May 1992)

"Making Utility Regulation Work at the Public Utility Commission of Texas," Center for Legal and Regulatory Studies, University of Texas, Austin (June 1991)

"Can Regulation Compete for the Hearts and Minds of Industrial Customers," Emerging Issues of Competition in the Electric Utility Industry Conference, Austin (May 1988)

"The Role of Utilities in Fostering New Energy Technologies," Emerging Energy Technologies in Texas Conference, Austin (Mar. 1988)

"The Regulators' Perspective," Bellcore Economic Analysis Conference, San Antonio (Nov. 1987)

"Public Utility Commissions and the Nuclear Plant Contractor," Construction Litigation Superconference, Laguna Beach, California (Dec. 1986)

"Development of Cogeneration Policies in Texas," University of Georgia Fifth Annual Public Utilities Conference, Atlanta (Sep. 1985)

"Wheeling for Power Sales," Energy Bureau Cogeneration Conference, Houston (Nov. 1985).

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"Used and Useful Planning Models," Planning Executive Institute, 27th Corporate Planning Conference, Los Angeles (Nov. 1979)

"Staff Input to Commission Rate of Return Decisions," The National Society of Rate of Return Analysts, New York (Oct. 1979)

"Electric Rate Design in Texas," Southwestern Economics Association, Fort Worth (Mar. 1979)

"Discounted Cash Life: A New Measure of the Time Dimension in Capital Budgeting," with David Cordell, Southern Finance Association, New Orleans (Nov. 1978)

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"A Growth-Optimal Portfolio Selection Model with Finite Horizon," with Henry A. Latané, American Finance Association, San Francisco (Dec. 1974)

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"A Pragmatic Approach to the Capital Structure Decision Based on Long-Run Growth," with Henry A. Latané, Financial Management Association, San Diego (Oct. 1974)

"Multi-period Wealth Distributions and Portfolio Theory," Southern Finance Association, Houston (Nov. 1973)

"Growth Rates, Expected Returns, and Variance in Portfolio Selection and Performance Evaluation," with Henry A. Latané, Econometric Society, Oslo, Norway (Aug. 1973)

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of William E. Avera
Constant Growth DCF Model (Utility Proxy Group)

July 31, 2009

CONSTANT GROWTH DCF MODEL

UTILITY PROXY GROUP

		(a)	(a)		(b)	(c)	(d)	(e)	(f)	(f)	(f)	(f)
		Dividend Yield			**Growth Rates**				**Cost of Equity Estimates**			
	Company	**Price**	**Dividends**	**Yield**	**V Line**	**IBES**	**Zacks**	**br+sv**	**V Line**	**IBES**	**Zacks**	**br+sv**
1	Allegheny Energy	$ 24.28	$ 0.60	2.5%	8.5%	16.3%	14.0%	10.1%	11.0%	18.8%	16.5%	12.5%
2	American Elec Pwr	$ 28.57	$ 1.64	5.7%	3.0%	3.3%	4.3%	6.0%	8.7%	9.0%	10.0%	11.7%
3	Avista Corp.	$ 17.92	$ 0.84	4.7%	6.5%	5.0%	8.7%	2.6%	11.2%	9.7%	13.4%	7.3%
4	Black Hills Corp.	$ 23.08	$ 1.43	6.2%	6.5%	6.0%	6.0%	3.2%	12.7%	12.2%	12.2%	9.4%
5	CenterPoint Energy	$ 10.94	$ 0.78	7.1%	3.0%	NA	7.0%	9.7%	10.1%	NA	14.1%	16.8%
6	Cleco Corp.	$ 22.07	$ 0.95	4.3%	9.5%	11.7%	14.5%	4.9%	13.8%	16.0%	18.8%	9.2%
7	CMS Energy	$ 11.88	$ 0.55	4.6%	10.0%	6.7%	6.5%	5.1%	14.6%	11.3%	11.1%	9.7%
8	DPL, Inc.	$ 22.88	$ 1.14	5.0%	8.0%	7.4%	6.3%	12.2%	13.0%	12.4%	11.3%	17.2%
9	DTE Energy Co.	$ 31.36	$ 2.12	6.8%	7.5%	3.5%	6.0%	4.1%	14.3%	10.3%	12.8%	10.8%
10	Edison International	$ 30.51	$ 1.25	4.1%	3.5%	1.3%	6.3%	7.3%	7.6%	5.4%	10.4%	11.4%
11	IDACORP, Inc.	$ 25.22	$ 1.20	4.8%	4.5%	5.0%	5.0%	4.6%	9.3%	9.8%	9.8%	9.3%
12	ITC Holdings Corp.	$ 43.02	$ 1.28	3.0%	12.5%	16.0%	12.5%	8.6%	NA	19.0%	15.5%	11.6%
13	NiSource Inc.	$ 11.71	$ 0.92	7.9%	1.0%	1.6%	2.7%	2.1%	8.9%	9.5%	10.6%	9.9%
14	Northeast Utilities	$ 22.06	$ 0.98	4.4%	8.0%	7.5%	8.0%	6.2%	12.4%	11.9%	12.4%	10.7%
15	Pepco Holdings	$ 12.88	$ 1.08	8.4%	3.0%	3.7%	4.0%	3.6%	11.4%	12.1%	12.4%	12.0%
16	PG&E Corp.	$ 38.01	$ 1.71	4.5%	6.5%	6.9%	7.1%	6.7%	11.0%	11.4%	11.6%	11.2%
17	Portland General Elec.	$ 18.93	$ 1.02	5.4%	5.5%	7.1%	6.7%	4.4%	10.9%	12.5%	12.1%	9.7%
18	PPL Corp.	$ 31.80	$ 1.49	4.7%	10.5%	12.7%	9.0%	9.6%	15.2%	17.4%	13.7%	14.3%
19	Progress Energy	$ 37.55	$ 2.48	6.6%	6.0%	5.4%	4.7%	3.3%	12.6%	12.0%	11.3%	9.9%
20	P S Enterprise Group	$ 31.25	$ 1.37	4.4%	7.5%	5.7%	5.8%	8.2%	11.9%	10.1%	10.2%	12.6%
21	TECO Energy	$ 11.49	$ 0.80	7.0%	4.5%	8.5%	10.2%	4.6%	11.5%	15.5%	17.2%	11.5%
22	UIL Holdings	$ 22.21	$ 1.73	7.8%	2.5%	4.5%	4.1%	3.1%	10.3%	12.3%	11.9%	10.9%
23	Westar Energy	$ 18.27	$ 1.20	6.6%	4.0%	3.4%	5.7%	2.9%	10.6%	10.0%	12.3%	9.4%
24	Wisconsin Energy	$ 40.87	$ 1.45	3.5%	8.0%	9.0%	8.5%	6.4%	11.5%	12.5%	12.0%	10.0%
25	Xcel Energy, Inc.	$ 18.17	$ 0.98	5.4%	6.5%	6.3%	5.3%	4.9%	11.9%	11.7%	10.7%	10.3%
	Average (g)								**11.7%**	**11.6%**	**12.1%**	**11.1%**

(a) Recent price and estimated dividend for next 12 mos. from The Value Line Investment Survey, *Summary and Index* (July 17, 2009).

(b) The Value Line Investment Survey (May 8, May 29, & June 26, 2009).

(c) *Thomson Reuters Company Report* (July 13, 2009).

(d) http://www.zacks.com/research (retrieved July 14, 2009).

(e) See Table 2.

(f) Sum of dividend yield and respective growth rate.

(g) Excludes highlighted figures.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of William E. Avera
Sustainable Growth (Utility Proxy Group)

July 31, 2009

SUSTAINABLE GROWTH

UTILITY PROXY GROUP

		(a)	(a)	(a)	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Projections			2008		Mid-Year					
				Net Book	Net Book	Annual	Adjustment		Adjusted	"b x r"	"sv"	Sustainable
	Company	EPS	DPS	Value	Value	Change	Factor	"b"	"r"	growth	Factor	Growth
1	Allegheny Energy	$3.65	$1.20	$27.85	$16.83	10.6%	1.0503	67.1%	13.8%	9.2%	0.82%	10.1%
2	American Elec Pwr	$3.50	$1.90	$33.25	$26.33	4.8%	1.0233	45.7%	10.8%	4.9%	1.07%	6.0%
3	Avista Corp.	$1.75	$1.25	$21.50	$18.30	3.3%	1.0161	28.6%	8.3%	2.4%	0.20%	2.6%
4	Black Hills Corp.	$2.50	$1.56	$30.50	$27.19	2.3%	1.0115	37.6%	8.3%	3.1%	0.05%	3.2%
5	CenterPoint Energy	$1.50	$0.92	$9.00	$5.89	8.8%	1.0424	38.7%	17.4%	6.7%	2.95%	9.7%
6	Cleco Corp.	$2.50	$1.60	$22.75	$17.65	5.2%	1.0254	36.0%	11.3%	4.1%	0.82%	4.9%
7	CMS Energy	$1.50	$0.80	$14.50	$10.88	5.9%	1.0287	46.7%	10.6%	5.0%	0.11%	5.1%
8	DPL, Inc.	$2.65	$1.30	$13.90	$8.41	10.6%	1.0502	50.9%	20.0%	10.2%	2.05%	12.2%
9	DTE Energy Co.	$4.00	$2.50	$41.00	$36.77	2.2%	1.0109	37.5%	9.9%	3.7%	0.39%	4.1%
10	Edison International	$4.25	$1.50	$39.00	$29.21	6.0%	1.0289	64.7%	11.2%	7.3%	0.00%	7.3%
11	IDACORP, Inc.	$2.75	$1.20	$35.60	$27.76	5.1%	1.0249	56.4%	7.9%	4.5%	0.11%	4.6%
12	ITC Holdings Corp.	$3.25	$1.50	$25.50	$18.71	6.4%	1.0310	53.8%	13.1%	7.1%	1.53%	8.6%
13	NiSource Inc.	$1.30	$0.92	$18.35	$17.24	1.3%	1.0062	29.2%	7.1%	2.1%	-0.02%	2.1%
14	Northeast Utilities	$2.25	$1.15	$25.25	$19.38	5.4%	1.0265	48.9%	9.1%	4.5%	1.77%	6.2%
15	Pepco Holdings	$1.90	$1.08	$22.10	$19.14	2.9%	1.0144	43.2%	8.7%	3.8%	-0.19%	3.6%
16	PG&E Corp.	$4.25	$2.20	$35.75	$25.97	6.6%	1.0319	48.2%	12.3%	5.9%	0.81%	6.7%
17	Portland General Elec.	$2.25	$1.30	$25.00	$21.64	2.9%	1.0144	42.2%	9.1%	3.9%	0.50%	4.4%
18	PPL Corp.	$4.50	$2.40	$21.25	$13.55	9.4%	1.0450	46.7%	22.1%	10.3%	-0.74%	9.6%
19	Progress Energy	$3.60	$2.56	$36.80	$32.55	2.5%	1.0123	28.9%	9.9%	2.9%	0.39%	3.3%
20	P S Enterprise Group	$3.75	$1.70	$24.50	$15.36	9.8%	1.0467	54.7%	16.0%	8.8%	-0.54%	8.2%
21	TECO Energy	$1.40	$0.90	$11.75	$9.43	4.5%	1.0220	35.7%	12.2%	4.3%	0.21%	4.6%
22	UIL Holdings	$2.20	$1.73	$19.40	$18.85	0.6%	1.0029	21.4%	11.4%	2.4%	0.69%	3.1%
23	Westar Energy	$2.15	$1.40	$27.20	$20.18	6.2%	1.0298	34.9%	8.1%	2.8%	0.01%	2.9%
24	Wisconsin Energy	$4.50	$2.15	$37.75	$28.54	5.8%	1.0280	52.2%	12.3%	6.4%	0.01%	6.4%
25	Xcel Energy, Inc.	$2.00	$1.10	$19.00	$15.35	4.4%	1.0213	45.0%	10.8%	4.8%	0.07%	4.9%

(a) The Value Line Investment Survey (May 8, May 29, & June 26, 2009).
(b) Annual growth in book value per share from historical to projected period.
(c) Equal to 2(1+b)/(2+b), where b = annual change in net book value.
(d) (EPS-DPS)/EPS.
(e) (Projected EPS/Projected Net Book Value) x Mid-Year Adjustment Factor.
(f) (d) x (e).
(g) "s" equals projected market-to-book ratio x growth in common shares. "v" equals (1- 1/projected market-to-book ratio).
(h) (f) + (g).

Idaho Power/204
Witness: William E. Avera

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of William E. Avera
Electric Utility Proxy Group (CAPM Model)

July 31, 2009

ELECTRIC UTILITY PROXY GROUP

CAPM MODEL

	Company	(a) S&P 500 Div Yield	(b) S&P 500 Proj. Growth	(c) S&P 500 Cost of Equity	(d) Risk-Free Rate	(e) Risk Premium	(f) Beta	(g) Implied Cost of Equity
1	Allegheny Energy	4.4%	9.1%	13.5%	4.5%	9.0%	1.00	13.5%
2	American Elec Pwr	4.4%	9.1%	13.5%	4.5%	9.0%	0.75	11.2%
3	Avista Corp.	4.4%	9.1%	13.5%	4.5%	9.0%	0.70	10.8%
4	Black Hills Corp.	4.4%	9.1%	13.5%	4.5%	9.0%	0.80	11.7%
5	CenterPoint Energy	4.4%	9.1%	13.5%	4.5%	9.0%	0.85	12.1%
6	Cleco Corp.	4.4%	9.1%	13.5%	4.5%	9.0%	0.70	10.8%
7	CMS Energy	4.4%	9.1%	13.5%	4.5%	9.0%	0.80	11.7%
8	DPL, Inc.	4.4%	9.1%	13.5%	4.5%	9.0%	0.60	9.9%
9	DTE Energy Co.	4.4%	9.1%	13.5%	4.5%	9.0%	0.75	11.2%
10	Edison International	4.4%	9.1%	13.5%	4.5%	9.0%	0.80	11.7%
11	IDACORP, Inc.	4.4%	9.1%	13.5%	4.5%	9.0%	0.70	10.8%
12	ITC Holdings Corp.	4.4%	9.1%	13.5%	4.5%	9.0%	0.85	12.1%
13	NiSource Inc.	4.4%	9.1%	13.5%	4.5%	9.0%	0.85	12.1%
14	Northeast Utilities	4.4%	9.1%	13.5%	4.5%	9.0%	0.70	10.8%
15	Pepco Holdings	4.4%	9.1%	13.5%	4.5%	9.0%	0.80	11.7%
16	PG&E Corp.	4.4%	9.1%	13.5%	4.5%	9.0%	0.60	9.9%
17	Portland General Elec.	4.4%	9.1%	13.5%	4.5%	9.0%	0.70	10.8%
18	PPL Corp.	4.4%	9.1%	13.5%	4.5%	9.0%	0.70	10.8%
19	Progress Energy	4.4%	9.1%	13.5%	4.5%	9.0%	0.65	10.3%
20	P S Enterprise Group	4.4%	9.1%	13.5%	4.5%	9.0%	0.80	11.7%
21	TECO Energy	4.4%	9.1%	13.5%	4.5%	9.0%	0.80	11.7%
22	UIL Holdings	4.4%	9.1%	13.5%	4.5%	9.0%	0.70	10.8%
23	Westar Energy	4.4%	9.1%	13.5%	4.5%	9.0%	0.75	11.2%
24	Wisconsin Energy	4.4%	9.1%	13.5%	4.5%	9.0%	0.65	10.3%
25	Xcel Energy, Inc.	4.4%	9.1%	13.5%	4.5%	9.0%	0.65	10.3%
	Range							**9.9% -- 13.5%**
	Average							**11.2%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (retreived Mar. 13, 2009).

(b) Weighted average of Value Line, IBES, First Call, and Zacks earnings growth rates for the dividend paying firms in the S&P 500 based on data from www.valueline.com (retrieved Mar. 13, 2009), Thomson Reuters Company in Context Report (Mar. 16, 2009), First Call Valuation Report (Mar. 17, 2009), and www.zacks.com (retrieved Mar. 18, 2009).

(c) (a) + (b).

(d) Average yield on 20-year Treasury bonds for June 2009 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data.htm.

(e) (c) - (d).

(f) The Value Line Investment Survey (May 8, & May 29, & June 26, 2009).

(g) (d) + (e) x (f).

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of William E. Avera
Expected Earnings Approach (Utility Proxy Group)

July 31, 2009

EXPECTED EARNINGS APPROACH

UTILITY PROXY GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	Allegheny Energy	13.0%	1.0503	13.7%
2	American Elec Pwr	10.5%	1.0233	10.7%
3	Avista Corp.	8.0%	1.0161	8.1%
4	Black Hills Corp.	8.5%	1.0115	8.6%
5	CenterPoint Energy	18.0%	1.0424	18.8%
6	Cleco Corp.	11.5%	1.0254	11.8%
7	CMS Energy	11.0%	1.0287	11.3%
8	DPL, Inc.	19.5%	1.0502	20.5%
9	DTE Energy Co.	9.5%	1.0109	9.6%
10	Edison International	11.0%	1.0289	11.3%
11	IDACORP, Inc.	7.5%	1.0249	7.7%
12	ITC Holdings Corp.	13.0%	1.0310	13.4%
13	NiSource Inc.	7.0%	1.0062	7.0%
14	Northeast Utilities	8.5%	1.0265	8.7%
15	Pepco Holdings	8.5%	1.0144	8.6%
16	PG&E Corp.	12.5%	1.0319	12.9%
17	Portland General Elec.	9.0%	1.0144	9.1%
18	PPL Corp.	22.0%	1.0450	23.0%
19	Progress Energy	9.5%	1.0123	9.6%
20	P S Enterprise Group	16.0%	1.0467	16.7%
21	TECO Energy	12.0%	1.0220	12.3%
22	UIL Holdings	11.0%	1.0029	11.0%
23	Westar Energy	8.0%	1.0298	8.2%
24	Wisconsin Energy	12.0%	1.0280	12.3%
25	Xcel Energy, Inc.	10.5%	1.0213	10.7%
	Average (d)			**11.3%**

(a) 3-5 year projections from The Value Line Investment Survey (May 8, May 29, & June 26, 2009).
(b) Adjustment to convert year-end "r" to an average rate of return from Table 2.
(c) (a) x (b).
(d) Excludes highlighted figures.

Idaho Power/206
Witness: William E. Avera

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of William E. Avera
Testimony and Exhibits in 2008 Idaho Rate Case, Case No. IPC-E-08-10

July 31, 2009

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE.	)))))	CASE NO. IPC-E-08-10

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

WILLIAM E. AVERA

DIRECT TESTIMONY OF WILLIAM E. AVERA

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. William E. Avera, 3907 Red River, Austin, Texas, 78751.

Q. In what capacity are you employed?

A. I am the President of FINCAP, Inc., a firm providing financial, economic, and policy consulting services to business and government.

Q. Please describe your educational background and professional experience.

A. I received a B.A. degree with a major in economics from Emory University. After serving in the U.S. Navy, I entered the doctoral program in economics at the University of North Carolina at Chapel Hill. Upon receiving my Ph.D., I joined the faculty at the University of North Carolina and taught finance in the Graduate School of Business. I subsequently accepted a position at the University of Texas at Austin where I taught courses in financial management and investment analysis. I then went to work for International Paper Company in New York City as Manager of Financial Education, a position in which I had responsibility for all corporate education programs in finance, accounting, and economics.

In 1977, I joined the staff of the Public Utility Commission of Texas ("PUCT") as Director of the Economic

Research Division. During my tenure at the PUCT, I managed a division responsible for financial analysis, cost allocation and rate design, economic and financial research, and data processing systems, and I testified in cases on a variety of financial and economic issues. Since leaving the PUCT, I have been engaged as a consultant. I have participated in a wide range of assignments involving utility-related matters on behalf of utilities, industrial customers, municipalities, and regulatory commissions. I have previously testified before the Federal Energy Regulatory Commission ("FERC"), as well as the Federal Communications Commission, the Surface Transportation Board (and its predecessor, the Interstate Commerce Commission), the Canadian Radio-Television and Telecommunications Commission, and regulatory agencies, courts, and legislative committees in 40 states.

In 1995, I was appointed by the PUCT to the Synchronous Interconnection Committee to advise the Texas legislature on the costs and benefits of connecting Texas to the national electric transmission grid. In addition, I served as an outside director of Georgia System Operations Corporation, the system operator for electric cooperatives in Georgia.

I have served as Lecturer in the Finance Department at the University of Texas at Austin and taught in the evening graduate program at St. Edward's University for twenty years. In addition, I have lectured on economic and regulatory topics in programs sponsored by universities and industry groups. I have taught in hundreds of educational programs for financial analysts in programs sponsored by the Association for Investment Management and Research, the Financial Analysts Review, and local financial analysts societies. These programs have been presented in Asia, Europe, and North America, including the Financial Analysts Seminar at Northwestern University. I hold the Chartered Financial Analyst (CFA®) designation and have served as Vice President for Membership of the Financial Management Association. I have also served on the Board of Directors of the North Carolina Society of Financial Analysts. I was elected Vice Chairman of the National Association of Regulatory Commissioners ("NARUC") Subcommittee on Economics and appointed to NARUC's Technical Subcommittee on the National Energy Act. I have also served as an officer of various other professional organizations and societies. A resume containing the details of my experience and qualifications is attached as Exhibit No. 16.

A. Overview

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

A. The purpose of my testimony is to present to the Idaho Public Utilities Commission (the "Commission" or "IPUC") my independent evaluation of the fair rate of return on equity ("ROE") for the jurisdictional utility operations of Idaho Power Company ("Idaho Power" or "the Company"). The overall rate of return applied to Idaho Power's 2008 test year rate base is developed in the testimony of Mr. Steve Keen.

Q. Please summarize the basis of your knowledge and conclusions concerning the issues to which you are testifying in this case.

A. As is common and generally accepted in my field of expertise, I have accessed and used information from a variety of sources. I am familiar with the organization, operations, finances, and operation of Idaho Power from my participation in prior proceedings before the IPUC, the Oregon Public Utility Commission, and the FERC. In connection with the present filing, I considered and relied upon corporate disclosures and management discussions, publicly available financial reports and filings, and other published information relating to the Company and its parent, IDACORP, Inc. ("IDACORP"). I also reviewed information relating generally to current capital market conditions and specifically to current investor perceptions, requirements, and expectations for Idaho Power's electric utility operations. These sources, coupled with my experience in the fields of finance and utility regulation, have given me a working knowledge of investors' ROE requirements for Idaho Power as it competes to attract capital, and form the basis of my analyses and conclusions.

Q. What is the role of ROE in setting a utility's rates?

A. The ROE serves to compensate investors for the use of their capital to finance the plant and equipment necessary to provide utility service. Investors commit capital only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks. To be consistent with sound regulatory economics and the standards set forth by the Supreme Court in the *Bluefield*[1] and *Hope*[2] cases, a utility's allowed ROE should be sufficient to: 1) fairly compensate the utility's investors, 2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and 3) maintain the utility's financial integrity.

Q. How did you go about developing your conclusions regarding a fair rate of return for Idaho Power?

A. I first reviewed the operations and finances of Idaho Power and the general conditions in the utility industry and the economy. With this as a background, I conducted various well-accepted quantitative analyses to estimate the current cost of equity, including alternative applications of the discounted cash flow ("DCF") model and

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[1] Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n, 262 U.S. 679 (1923).

[2] Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944).

the Capital Asset Pricing Model ("CAPM"), as well as reference to comparable earned rates of return expected for utilities. Based on the cost of equity estimates indicated by my analyses, the Company's ROE was evaluated taking into account the specific risks and economic requirements for Idaho Power consistent with preservation of its financial integrity.

B. Summary of Conclusions

Q. What are your findings regarding the fair rate of return on equity for Idaho Power?

A. Based on the results of my analyses and the economic requirements necessary to support continuous access to capital, I recommend that Idaho Power be authorized a fair rate of return on equity in the 10.8 percent to 11.8 percent range. The bases for my conclusion are summarized below:

- In order to reflect the risks and prospects associated with Idaho Power's jurisdictional utility operations, my analyses focused on a proxy group of twenty-seven electric utilities with comparable investment risks. Consistent with the fact that utilities must compete for capital with firms outside their own industry, I also referenced a proxy group of comparable risk companies in the non-utility sector of the economy;
- I applied both the DCF and CAPM methods, as well as the comparable earnings approach, to estimate a fair ROE for Idaho Power:
  - o My application of the constant growth DCF model considered three alternative growth measures based on projected earnings growth, as well as the sustainable, "br+sv" growth rate for each firm in the respective proxy groups;

- After eliminating low- and high-end outliers, my DCF analyses implied a cost of equity of 11.0 percent for the proxy group of electric utilities and 12.6 percent for the group of non-utility companies;
- Application of the CAPM approach using forward-looking data that best reflects the underlying assumptions of this approach implied a cost of equity of 12.3 percent for the electric utilities and 11.5 percent for the non-utility companies;
- Applying the CAPM method using historical realized rates of return resulted in a cost of equity of 10.8 percent for the proxy group of utilities and 10.2 percent for the firms in the non-utility proxy group;
- My evaluation of comparable earned rates of return expected for utilities suggested a cost of equity on the order of at least 11.1 percent for the proxy group of electric utilities;
- Considering these results, and conservatively giving less weight to the upper end of the range, I concluded that the cost of equity for the proxy groups of electric utilities and non-utility companies is on the order of 10.8 percent to 11.8 percent;
- Considering investors' expectations for capital markets and the need to support financial integrity and fund crucial capital investment even under adverse circumstances, it is my opinion that this 10.8 percent to 11.8 percent range bounds a reasonable rate of return on common equity for Idaho Power; and,
- While this "bare-bones" cost of equity range does not consider issuance costs, a flotation cost adder is properly considered in establishing an allowed ROE for Idaho Power from within this range.

Q. What is your conclusion as to the reasonableness of the Company's capital structure?

A. Based on my evaluation, I concluded that a common equity ratio of approximately 49 percent represents a reasonable basis from which to calculate Idaho Power's overall rate of return. This conclusion was based on the following findings:

- Idaho Power's proposed common equity ratio is entirely consistent with range of capitalizations maintained by the firms in the proxy group of electric utilities at year-end 2007 and based on investors' expectations;

- My conclusion is reinforced by the investment community's focus on the need for a greater equity cushion to accommodate higher operating risks, including the uncertainties posed by exposure to variable hydro conditions, and the pressures of capital investments. Financial flexibility plays a crucial role in ensuring the wherewithal to meet the needs of customers, and Idaho Power's capital structure reflects the Company's ongoing efforts to support its credit standing and maintain access to capital on reasonable terms.

Q. What other evidence did you consider in evaluating your recommendation in this case?

A. My recommendation was reinforced by the following findings:

- Sensitivity to regulatory uncertainties has increased dramatically and investors recognize that constructive regulation is a key ingredient in supporting utility credit standing and financial integrity;

- Because of Idaho Power's reliance on hydroelectric generation, the Company is exposed to relatively greater risks of power cost volatility;

- Investors recognize that Idaho Power's Power Cost Adjustment Mechanism ("PCA") provides some level of support for the Company's financial integrity, but they understand that the PCA does not apply to 100 percent of power costs; nor does it insulate Idaho Power from the need to finance accrued power production and supply costs or shield the Company from potential regulatory disallowances.

- Idaho Power must compete for investors' capital with other utilities and businesses of comparable risk. If Idaho Power is not provided an opportunity to earn a return that is sufficient to compensate for the underlying risks, investors will be unwilling to supply capital;

- Providing Idaho Power with the opportunity to earn a return that reflects these realities is an essential ingredient to support the Company's financial position, which ultimately benefits customers by ensuring reliable service at lower long-run costs;

- Past challenges confronting the utility industry illustrate the need to ensure that Idaho Power has the ability to respond effectively to unforeseen events.

Ultimately, it is customers and the service area economy that enjoy the rewards that come from ensuring that the utility has the financial wherewithal to take whatever actions are necessary to provide a reliable energy supply.

II. FUNDAMENTAL ANALYSES

Q. What is the purpose of this section?

A. As a predicate to my economic and capital market analyses, this section examines conditions in the utility industry generally, and for Idaho Power specifically, that investors consider in evaluating their required rate of return. An understanding of these fundamental factors, which drive the risks and prospects for Idaho Power, is essential to develop an informed opinion about investor expectations and requirements that form the basis of a fair rate of return on equity.

A. Idaho Power Company

Q. Briefly describe Idaho Power.

A. Idaho Power is a wholly-owned subsidiary of IDACORP, Inc. ("IDACORP") and is principally engaged in providing integrated retail electric utility service in a 24,000 square mile area in southern Idaho and eastern Oregon. During 2007, Idaho Power's energy deliveries totaled 17.3 million megawatt hours ("MWh"). Sales to residential customers comprised 36 percent of retail sales, with 27 percent to commercial, 24 percent to industrial end-users, and 13 percent attributable to irrigation pumping. Idaho Power also supplies firm wholesale power service to various utilities and large customers under sales contracts. IPC's service territory experienced record-setting high temperatures during 2007 and due to these weather conditions and continued customer growth, IPC set three new all-time system peaks. At year-end 2007, Idaho Power had total assets of $3.5 billion, with total revenues amounting to approximately $875 million.

In addition to its thermal baseload and peaking units located in Wyoming, Nevada and Idaho, Idaho Power's existing generating units include 17 hydroelectric generating plants located in southern Idaho and eastern Oregon. The electrical output of these hydro plants, which has a significant impact on total energy costs, is dependent on streamflows. Although Idaho Power estimates that hydroelectric generation is capable of supplying approximately 55 percent of total system requirements under normal conditions, the Company has experienced prolonged periods of persistent below-normal water conditions in the past.

Because approximately one-half of Idaho Power's total energy requirements are provided by hydroelectric facilities, the Company is exposed to a level of uncertainty not faced by most utilities. While hydropower confers advantages in terms of fuel cost savings and diversity, reduced hydroelectric generation due to below-average water conditions forces Idaho Power to rely more heavily on wholesale power markets or more costly thermal generating capacity to meet its resource needs. As Standard & Poor's Corporation ("S&P") recently observed:

> A reduction in hydro generation typically increases an electric utility's costs by requiring it to buy replacement power or run more expensive generation to serve customer loads. Low hydro generation can also reduce utilities' opportunity to make off-system sales. At the same time, low hydro years increase regional wholesale power prices, creating potentially a double impact – companies have to buy more power than under normal conditions, paying higher prices.[3]

Investors recognize that uncertainties over water conditions are a persistent operational risk associated with Idaho

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[3] Standard & Poor's Corporation, "Pacific Northwest Hydrology And Its Impact On Investor-Owned Utilities' Credit Quality," *RatingsDirect* (Jan. 28, 2008).

Power. In addition to weather-related fluctuations in water flows, Idaho Power is also exposed to uncertainties regarding water rights and the administration of those rights.

Idaho Power's retail electric operations are subject to the jurisdiction of the IPUC and the Oregon Public Utility Commission, with the interstate jurisdiction regulated by FERC. Additionally, Idaho Power's hydroelectric facilities are subject to licensing under the Federal Power Act, which is administered by FERC, as well as the Oregon Hydroelectric Act. Relicensing is not automatic under federal law, and Idaho Power must demonstrate that it has operated its facilities in the public interest, which includes adequately addressing environmental concerns. The most significant of Idaho Power's relicensing efforts concerns its Hells Canyon Complex ("Hells Canyon"), which represents 68 percent of the Company's hydro capacity and 40 percent of its total generating capability.

In June 2003, after a prolonged period of planning and consultation with interested parties, Idaho Power submitted a license application for Hells Canyon that included various protection, mitigation, and enhancement measures in order to address environmental concerns while preserving the peak and load following operations of the facilities. The current license for Hells Canyon expired at the end of July 2005 and until the new multi-year license is issued, Idaho Power will operate the project under an annual license issued by FERC. Apart from significant ongoing expenditures associated with proposed environmental measures, the relicensing process is complex, protracted, and expensive. As of December 31, 2007, Idaho Power had accumulated $96 million of construction work in progress associated with its Hells Canyon relicensing efforts.

Q. How are fluctuations in Idaho Power's operating expenses caused by varying hydro and power market conditions accommodated in its rates?

A. Beginning in May 1993, Idaho Power implemented a PCA, under which rates are adjusted annually to reflect changes in variable power production and supply costs. When hydroelectric generation is reduced and power supply costs rise above those included in base rates, the PCA allows Idaho Power to increase rates to recover a portion of its additional costs. Conversely, rates are reduced when increased hydroelectric generation leads to lower power supply costs. Although the PCA provides for rates to be adjusted annually, it applies to 90 percent of the deviation between actual power supply costs and normalized rates.

Q. Are there other mechanisms that affect Idaho Power's rates for utility service?

A. Yes. Included in the provisions of Idaho Power's PCA is a Load Growth Adjustment Rate ("LGAR"). The LGAR subtracts the cost of serving new Idaho retail customers from the power supply costs that the Company is allowed to include in its PCA. The IPUC has recognized that Idaho Power would nevertheless continue to be exposed to the risks of shortfalls associated with load growth. The IPUC specifically noted that these uncertainties are properly considered in establishing a fair ROE for Idaho Power:

> Because this process puts the Company at some business and financial risk, it is awarded a commensurate equity return. Idaho Power's current equity return was set in a process that recognized it would not recover the power supply costs of load growth in the PCA mechanism.[4]

In 2007 the IPUC also approved a Fixed Cost Adjustment Mechanism ("FCA") for Idaho Power under a three-year pilot program applicable to residential and small commercial customer classes. The FCA adjusts rates upward or downward to insulate the recovery of fixed costs from the volume of Idaho Power's energy sales. The pilot program includes various provisions related to customer count and weather normalization methodology, reporting requirements, and detailed disclosure of demand-side management activities.

Q. What credit ratings have been assigned to Idaho Power?

A. Citing concerns over deteriorating financial metrics and the outcome of Idaho Power's last rate proceeding before the IPUC, S&P lowered Idaho Power's

[4] Order No. 30215 at 10.

corporate credit rating from "BBB+" to "BBB" in January 2008.[5] While Moody's Investors Service ("Moody's) has so far maintained the Company's issuer rating at "Baa1", it recently revised its outlook for Idaho Power to "negative" based on similar concerns, warning investors of the potential for a downgrade in the Company's credit standing going forward.[6] Fitch Ratings Ltd. ("Fitch") has assigned the Company an issuer default rating of "BBB" and, like Moody's, has revised Idaho Power's Ratings Outlook to "negative."[7]

Q. Does Idaho Power anticipate the need to access the capital markets going forward?

A. Most definitely. Idaho Power will require capital investment to meet customer growth, provide for necessary maintenance and replacements of its utility infrastructure, as well as fund new investment in electric generation, transmission and distribution facilities. Idaho Power's service area has experienced strong population growth, and the Company's most recent resource plan anticipates the addition of 11,000 to 12,000 new customers annually.[8] In

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[5] Standard & Poor's Corporation, "IDACORP, Idaho Power Co. Ratings Lowered One Notch To 'BBB'; Outlook Stable," *RatingsDirect* (Jan. 31, 2008).

[6] Moody's Investors Service, "Moody's Changes Outlook Of Idacorp And Sub To Negative," *Press Release* (June 3, 2008).

[7] Fitch Ratings Ltd., "Idaho Power Company," *Global Power U.S. and Canada Credit Analysis* (Apr. 10, 2008).

[8] Idaho Power Company, *2006 Integrated Resource Plan* (Oct. 12, 2006) at 1.

order to keep pace with customer growth, enhance transmission infrastructure, and balance generation resource uncertainty Idaho Power anticipates construction expenditures of approximately $900 million over the period 2008-2010.[9]

Over the ten-year planning period, Idaho Power's Integrated Resource Plan has identified the potential need for the Company to obtain 1,063 MW of supply-side capacity, which will entail additional purchased power commitments and financing construction of additional baseload generation, in addition to other system upgrades.[10] Moreover, as indicated earlier, Idaho Power must also bear the costs of protection, mitigation, and enhancement measures associated with Hells Canyon relicensing. Considering the unfavorable outlook for the Company's credit standing, support for Idaho Power's financial integrity and flexibility will be instrumental in attracting the capital necessary to fund these projects in an effective manner.

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[9] IDACORP, Inc., *2007 Form-10K Report* at 27. This amount excludes expenditures for a 250-MW combined cycle combustion turbine expected to be operational in mid-2012 as well as any estimated costs attributable to the Gateway West Project, which contemplates construction of two 500-kV transmission lines with an estimated cost to Idaho Power of between $800 million and $1.2 billion.

[10] Idaho Power Company, *2006 Integrated Resource Plan* (Oct. 12, 2006) at 95.

B. Utility Industry

Q. How have investors' risk perceptions for firms involved in the utility industry evolved?

A. Since the 1990s, the industry has experienced significant structural change resulting from market forces and legislative and regulatory initiatives. Implementation of structural change and related events caused investors to rethink their assessment of the relative risks associated with the utility industry. The past decade witnessed steady erosion in credit quality throughout the utility industry, both as a result of revised perceptions of the risks in the industry and the weakened finances of the utilities themselves. S&P recently reported that the majority of the companies in the utility sector now fall in the triple-B rating category,[11] with Fitch recently concluding that "the long-term outlook is negative" for investor-owned electric utilities.[12] Similarly, Moody's observed, "Material negative bias appears to be developing over the intermediate and longer term due to rapidly rising business and operating risks."[13]

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[11] Standard & Poor's Corporation, "U.S. Electric utility Sector Continues To Benefit From Strong Liquidity Amid Current Credit Crunch," *RatingsDirect* (Mar. 27, 2008).

[12] Fitch Ratings, Ltd., "U.S. Utilities, Power and Gas 2008 Outlook," *Global Power North America Special Report* (Dec. 11, 2007).

[13] Moody's Investors Service, "U.S. Electric Utility Sector," *Industry Outlook* (Jan. 2008).

Q. What other key factors are of concern to investors?

A. In recent years, utilities and their customers have also had to contend with dramatic fluctuations in energy costs due to ongoing price volatility in the spot markets. Investors recognize that the prospect of further turmoil in energy markets is an ongoing concern. S&P has reported continued spikes in wholesale energy market prices,[14] with Moody's warning investors of ongoing exposure to "extremely volatile" energy commodity costs, including purchased power prices, which are heavily influenced by fuel costs.[15] Similarly, the FERC Staff has continued to recognize the ongoing potential for market disruption. A 2008 market assessment report recognized ongoing concerns regarding tight supply and congestion and observed that wholesale power prices across the nation are likely to be significantly higher than the previous year.[16] FERC continues to warn of load pockets vulnerable to periods of high peak demand and unplanned outages of generation or transmission capacity and ongoing reliability concerns that

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[14] Standard & Poor's Corporation, "Fuel and Purchased Power Cost Recovery in the Wake of Volatile Gas and Power Markets - U.S. Electric Utilities to Watch" *RatingsDirect* (Mar. 22, 2006).

[15] Moody's Investors Service, "Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector," *Special Comment* at 6 (Aug. 2007).

[16] FERC, Office of Market Oversight and Investigations, "2008 Summer Market and Reliability Assessment," (May 15, 2008).

led FERC to establish mandatory standards for the bulk power system.[17]

Additionally, in recent years, utilities and their customers have also had to contend with dramatic fluctuations in natural gas costs due to ongoing price volatility in the spot markets.[18] S&P observed that "natural gas prices have proven to be very volatile," warning of a "turbulent journey" due to the uncertainty associated with future fluctuations in energy costs,[19] and concluding: "Cost pressures from natural gas are not likely to recede in the near future."[20] Fitch also highlighted the challenges that fluctuations in commodity prices can have for utilities and their investors, concluding that gas prices are subject to near-term and longer-term fluctuations that contribute to an "adverse environment" for electric utilities.[21]

In addition, while coal-fired generation has historically provided relative stability with respect to

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[17] *See Open Commission Meeting Statement of Chairman Joseph T. Kelliher,* Item E-13: Mandatory Reliability Standards for the Bulk-Power System (Docket No. RM06-16-000) (Mar. 15, 2007).

[18] For example, the Department of Energy's Energy Information Administration ("EIA") reported that the average price of gas used by electricity generators (regulated utilities and non-regulated power producers) spiked from an average price of $7.18 per Mcf for the first eight months of 2005 to over $11.00 per Mcf in September and October 2005 (http://tonto.eia.doe.gov/dnav/ng/hist/n3045us3m.htm).

[19] Standard & Poor's Corporation, "Top Ten Credit Issues Facing U.S. Utilities," *RatingsDirect* (Jan. 29, 2007).

[20] *Id.*

[21] Fitch Ratings, Ltd., "U.S. Power and Gas 2008 Outlook," *Global Power North American Special Report,* at 3 (Dec. 11, 2007).

fuel costs, higher prices have raised investors' concerns. In a 2004 article entitled "Rising Coal Prices May Threaten U.S. Utility Credit Profiles," S&P noted that:

> More recently, several current and structural developments for the coal mining industry have resulted in a dramatic increase in spot coal prices.[22]

The EIA reported that average delivered coal prices for electric utilities increased 9.7 percent in 2006, the sixth consecutive annual rise,[23] while Reuters Inc. reported in May 2008 that benchmark coal prices exceeded $100 per ton, or over twice the levels of the previous fall.[24]

Q. What are the key uncertainties considered by investors in assessing their required rate of return for Idaho Power?

A. Because roughly one-half of Idaho Power's total energy requirements are provided by hydroelectric facilities, the Company is exposed to a level of uncertainty not faced by most utilities. While hydropower confers advantages in terms of fuel cost savings and diversity, reduced hydroelectric generation due to below-average water conditions forces Idaho Power to rely more heavily on

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[22] Standard & Poor's Corporation, "Rising Coal Prices May Threaten U.S. Utility Credit Profiles," *RatingsDirect* (Aug. 12, 2004).

[23] Energy Information Administration, *Annual Coal Report 2006* at 9 (Nov. 2007).

[24] Nichols, Bruce, "US coal prices pass $100 a ton, twice last fall's," *Reuters* (May 9, 2008).

purchased power or more costly thermal generating capacity to meet its resource needs.

The prolonged drought conditions experienced in the recent past have only deepened concerns over power prices and fluctuations in gas costs. As S&P noted, "hydro resources expose the company to substantial replacement power price risk in the event of low water flows."[25] S&P concluded that Idaho Power "has the greatest hydro exposure" of any utility and faces "the most substantial risks."[26] Investors recognize the significant financial burden that constrained hydro generation imposes on Idaho Power, as Moody's summarized:

> The company's recent financial metrics, including its coverage of interest and debt by cash flow from operations exclusive of working capital changes (CFO Pre-W/C), have been pressured to a level we often see for a regulated electric utility in the Ba rating category. These recent metrics are the result of unfavorable hydro conditions and the adverse effects the recent increase to the load growth adjustment rate (LGAR) has had on net power supply cost recovery under the power cost adjustment (PCA) mechanism.[27]

Similarly, Fitch concluded that its negative outlook on Idaho Power's ratings "primarily reflect persistent drought

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[25] Standard & Poor's Corporation, "IDACORP, Idaho Power Co. Ratings Lowered One Notch To 'BBB'; Outlook Stable," *RatingsDirect* (Jan. 31, 2008).

[26] Standard & Poor's Corporation, "Pacific Northwest Hydrology And Its Impact On Investor-Owned Utilities' Credit Quality," *RatingsDirect* (Jan. 28, 2008).

[27] Moody's Investors Service, "Credit Opinion: Idaho Power Company," *Global Credit Research* (June 4, 2008).

conditions in recent years and their adverse impact on the utility's cash flows, earnings and credit metrics."[28]

Volatile energy markets, unpredictable stream flows, and Idaho Power's reliance on wholesale purchases to meet a portion of its resource needs expose the Company to the risk of reduced cash flows and unrecovered power supply costs. The IPUC has recognized "the unique circumstances of Idaho Power's highly variable power supply costs."[29] The Company's reliance on purchased power to meet shortfalls in hydroelectric generation magnifies the importance of strengthening financial flexibility to ensure access to the cash resources and interim financing required to meet any shortfall in operating cash flows, as well as fund required investments in the utility system.

Q. Does the PCA remove the risk associated with fluctuations in power supply costs?

A. No. While the PCA provides some level of support for the Company's financial integrity, it does not apply to 100 percent of power costs. Moreover, even for utilities with permanent energy cost adjustment mechanisms in place, there can be a significant lag between the time the utility actually incurs the expenditure and when it is recovered from ratepayers. This lag can impinge on the utility's

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[28] Fitch Ratings, Ltd., "Idaho Power Company," *Global Power U.S. and Canada Credit Analysis* (Apr. 10, 2008).
[29] Order No. 30215 at 9.

financial strength through reduced liquidity and higher borrowings. As S&P observed:

> Because increased purchases and higher prices are not immediately met by increased retail revenues from customers, cash flows can decline in low water years. While PCAs and annual power cost updates can mitigate these effects, they are not designed to completely insulate a utility from poor hydro conditions. As a result, a large annual deviation from normal streamflow typically weakens cash coverage of debt and interest for a utility.[30]

S&P recently cited exposure to high deferred power costs resulting from "extremely variable" hydro generation as a key challenge facing Idaho Power.[31] Similarly, Moody's observed that the Company's financial metrics "are pressured relative to the current Baa1 rating and we expect that the company's financial performance will remain subject to the vagaries of water flow conditions."[32] Moreover, even with an energy cost adjustment mechanism, investors continue to recognize the ongoing potential for regulatory disallowances if the IPUC determines that the amounts were not prudently incurred.

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[30] Standard & Poor's Corporation, "Pacific Northwest Hydrology And Its Impact On Investor-Owned Utilities' Credit Quality," *RatingsDirect* (Jan. 28, 2008).

[31] Standard & Poor's Corporation, "Idaho Power Co.," *RatingsDirect* (Feb. 1, 2008).

[32] Moody's Investors Service, "Credit Opinion: Idaho Power Company," *Global Credit Research* (June 4, 2008).

Q. What other considerations affect investors' evaluation of Idaho Power?

A. Investors are aware of the financial and regulatory pressures faced by utilities associated with rising costs and the need to undertake significant capital investments. As Moody's observed:

> [T]here are concerns arising from the sector's sizeable infrastructure investment plans in the face of an environment of steadily rising operating costs. Combined, these costs and investments can create a continuous need for regulatory rate relief, which in turn can increase the likelihood for political and/or regulatory intervention.[33]

Similarly, S&P noted that "onerous construction programs", along with rising operating and maintenance costs and volatile fuel costs, were a significant challenge to the utility industry.[34] Moody's recently echoed this assessment, concluding, "There are significant negative trends developing over the longer-term horizon."[35]

While providing the infrastructure necessary to meet the energy needs of customers is certainly desirable, it imposes additional financial responsibilities on Idaho Power. As noted earlier, the Company's plans include

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[33] Moody's Investors Service, "Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector," *Special Comment* (Aug. 2007).

[34] Standard & Poor's Corporation, "U.S. Electric Utilities Continued Their Long Shift To Stability In Third Quarter," *RatingsDirect* (Oct. 23, 2007).

[35] Moody's Investors Service, "U.S. Utility Sector," *Industry Outlook* (Jan. 2008).

substantial capital expenditures, including enhancements to its transmission and distribution system and investment in generating resources. Investors are aware that the challenge of achieving timely regulatory recovery associated with rising costs and burdensome capital expenditure requirements impacts the Company's ability to earn a fair rate of return. For example, S&P cited "[r]egulatory challenges in meeting rising costs and a large capital expenditure program, resulting from high customer growth," as a key weakness for Idaho Power,[36] while Fitch noted that the inability to increase base rates to recover anticipated capital investment could lead to a downgrade in the Company's credit standing.[37]

In addition, electric utilities are confronting increased environmental pressures that are imposing significant uncertainties and costs. Utilities required to meet renewable portfolio standards and carbon reduction goals generally must embrace energy efficiency and conservation initiatives that lead to decreased demand and revenue erosion. In early 2007, S&P cited environmental mandates, including emissions, conservation, and renewable resources, as one of the top ten credit issues facing U.S.

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[36] Standard & Poor's Corporation, "Idaho Power Co.," *RatingsDirect* (Feb. 1, 2008).

[37] Fitch Ratings, Ltd., "Idaho Power Company," *Global Power U.S. and Canada Credit Analysis* (Apr. 10, 2008).

utilities.[38] More recently, S&P cited the long-term challenge posed by climate change legislation and observed that:

> What the ultimate outcome will be is cloudy right now, but legislation addressing carbon emissions and other greenhouse gases is extremely probable in the near future. The credit implications of any policy will be vast due to the compliance costs involved.[39]

Similarly, Moody's noted that "increasingly stringent environmental compliance mandates will elevate cash outflow recovery risk",[40] while Fitch noted that the electric utility industry would be "a primary target" of new environmental legislation, and concluded: "The murkiness of the future policies and regulations on carbon emissions is another factor clouding Fitch's long-term view of electric utilities."[41] Compliance with these evolving standards almost certainty will mean significant capital expenditures.

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[38] Standard & Poor's Corporation, "Top Ten Credit Issues Facing U.S. Utilities," *RatingsDirect* (Jan. 29, 2007).

[39] Standard & Poor's Corporation, "Upgrades Lead In U.S. Electric Utility Industry In 2007," *RatingsDirect* (Jan. 17, 2008).

[40] Moody's Investors Service, "U.S. Electric Utility Sector," *Industry Outlook* (Jan. 2008).

[41] Fitch Ratings, Ltd., "U.S. Utilities, Power and Gas 2008 Outlook," *Global Power North America Special Report* (Dec. 11, 2007).

Q. Have investors recognized that electric utilities face additional risks because of the impact of industry restructuring on transmission operations?

A. Yes. Policy evolution in the transmission area has been wide reaching and Idaho Power must address changes in the electric transmission function of its business. S&P confirmed a "continued lack of clarity from lawmakers and regulators on the regulatory framework surrounding transmission projects."[42] Transmission operations have become increasingly complex and investors have recognized that difficulties in obtaining permits and uncertainty over the adequacy of allowed rates of return have contributed to heightened risk and fueled concerns regarding the need for additional investment in the transmission sector of the electric power industry.

III. CAPITAL MARKET ESTIMATES

Q. What is the purpose of this section?

A. This section presents capital market estimates of the cost of equity. First, I examine the concept of the cost of equity, along with the risk-return tradeoff principle fundamental to capital markets. Next, I describe DCF and CAPM analyses conducted to estimate the cost of equity for benchmark groups of comparable risk firms and

[42] Standard & Poor's Corporation, "Capital Spending On Electric Transmission Is On The Upswing Around The World," *RatingsDirect* (Aug. 7, 2006).

evaluate comparable earned rates of return expected for utilities. Finally, I examine other factors (*e.g.*, flotation costs) that are properly considered in evaluating a fair rate of return on equity.

A. Overview

Q. What role does the rate of return on common equity play in a utility's rates?

A. The return on common equity is the cost of inducing and retaining investment in the utility's physical plant and assets. This investment is necessary to finance the asset base needed to provide utility service. Investors will commit money to a particular investment only if they expect it to produce a return commensurate with those from other investments with comparable risks. Moreover, the return on common equity is integral in achieving the sound regulatory objectives of rates that are sufficient to: 1) fairly compensate capital investment in the utility, 2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and 3) maintain the utility's financial integrity. Meeting these objectives allows the utility to fulfill its obligation to provide reliable service while meeting the needs of customers through necessary system expansion.

Q. What fundamental economic principle underlies any evaluation of investors' required return on equity?

A. The fundamental economic principle underlying the cost of equity concept is the notion that investors are risk averse. In capital markets where relatively risk-free assets are available (*e.g.*, U.S. Treasury securities), investors can be induced to hold riskier assets only if they are offered a premium, or additional return, above the rate of return on a risk-free asset. Because all assets compete with each other for investor funds, riskier assets must yield a higher expected rate of return than safer assets to induce investors to invest and hold them.

Given this risk-return tradeoff, the required rate of return (k) from an asset (i) can be generally expressed as:

$$k_i = R_f + RP_i$$

where: R_f = Risk-free rate of return; and
RP_i = Risk premium required to hold risky asset i.

Thus, the required rate of return for a particular asset at any point in time is a function of: 1) the yield on risk-free assets, and 2) its relative risk, with investors demanding correspondingly larger risk premiums for assets bearing greater risk.

Q. Is there evidence that the risk-return tradeoff principle actually operates in the capital markets?

A. Yes. The risk-return tradeoff can be readily documented in segments of the capital markets where required rates of return can be directly inferred from market data and where generally accepted measures of risk exist. Bond yields, for example, reflect investors' expected rates of return, and bond ratings measure the risk of individual bond issues. The observed yields on government securities, which are considered free of default risk, and bonds of various rating categories demonstrate that the risk-return tradeoff does, in fact, exist in the capital markets.

Q. Does the risk-return tradeoff observed with fixed income securities extend to common stocks and other assets?

A. It is generally accepted that the risk-return tradeoff evidenced with long-term debt extends to all assets. Documenting the risk-return tradeoff for assets other than fixed income securities, however, is complicated by two factors. First, there is no standard measure of risk applicable to all assets. Second, for most assets - including common stock - required rates of return cannot be directly observed. Yet there is every reason to believe that investors exhibit risk aversion in deciding whether or not to hold common stocks and other assets, just as when choosing among fixed-income securities.

Q. Is this risk-return tradeoff limited to differences between firms?

A. No. The risk-return tradeoff principle applies not only to investments in different firms, but also to different securities issued by the same firm. The securities issued by a utility vary considerably in risk because they have different characteristics and priorities. Long-term debt secured by a mortgage on property is senior among all capital in its claim on a utility's net revenues and is, therefore, the least risky. Following bonds are other debt instruments also holding contractual claims on the utility's net revenues, such as subordinated debentures. The last investors in line are common shareholders. They receive only the net revenues, if any, remaining after all other claimants have been paid. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by the utility's senior, long-term debt.

Q. What does the above discussion imply with respect to estimating the cost of equity for a utility?

A. Although the cost of equity cannot be observed directly, it is a function of the returns available from other investment alternatives and the risks to which the equity capital is exposed. Because it is unobservable, the cost of equity for a particular utility must be estimated by analyzing information about capital market conditions generally, assessing the relative risks of the company specifically, and employing various quantitative methods that focus on investors' required rates of return. These various quantitative methods typically attempt to infer investors' required rates of return from stock prices, interest rates, or other capital market data.

Q. Did you rely on a single method to estimate the cost of equity for Idaho Power?

A. No. I used both the DCF and CAPM methods to estimate the cost of equity, as well as referencing comparable earned rates of return expected for utilities. In my opinion, comparing estimates produced by one method with those produced by other approaches ensures that estimates of the cost of equity pass fundamental tests of reasonableness and economic logic. In addition, I applied the DCF and CAPM to alternative proxy groups of comparable risk firms.

Q. Are you aware that the IPUC has traditionally relied primarily on the DCF and comparable earnings methods?

A. Yes, although the Commission has also evidenced a willingness to weigh alternatives in evaluating an allowed ROE. For example, while noting that it had not focused on the CAPM for determining the cost of equity, the IPUC recognized in Order No. 29505 that "methods to evaluate a common equity rate of return are imperfect predictors" and emphasized "that by evaluating all the methods presented in this case and using each as a check on the other," the Commission had avoided the pitfalls associated with reliance on a single method.[43]

B. Discounted Cash Flow Analyses

Q. How are DCF models used to estimate the cost of equity?

A. DCF models attempt to replicate the market valuation process that sets the price investors are willing to pay for a share of a company's stock. The model rests on the assumption that investors evaluate the risks and expected rates of return from all securities in the capital markets. Given these expectations, the price of each stock is adjusted by the market until investors are adequately compensated for the risks they bear. Therefore, we can look to the market to determine what investors believe a share of common stock is worth. By estimating the cash flows investors expect to receive from the stock in the way of future dividends and capital gains, we can calculate their required rate of return. In other words, the cash flows that investors expect from a stock are estimated, and given its current market price, we can "back-into" the discount rate, or cost of equity, that investors implicitly used in bidding the stock to that price.

[43] Order No. 29505 at 38 (emphasis added).

Q. What market valuation process underlies DCF models?

A. DCF models assume that the price of a share of common stock is equal to the present value of the expected cash flows (i.e., future dividends and stock price) that will be received while holding the stock, discounted at investors' required rate of return. Thus, the cost of equity is the discount rate that equates the current price of a share of stock with the present value of all expected cash flows from the stock. Notationally, the general form of the DCF model is as follows:

$$P_0 = \frac{D_1}{(1+k_e)^1} + \frac{D_2}{(1+k_e)^2} + \cdots + \frac{D_t}{(1+k_e)^t} + \frac{P_t}{(1+k_e)^t}$$

where: P_0 = Current price per share;
P_t = Expected future price per share in period t;
D_t = Expected dividend per share in period t;
k_e = Cost of equity.

Q. What form of the DCF model is customarily used to estimate the cost of equity in rate cases?

A. Rather than developing annual estimates of cash flows into perpetuity, the DCF model can be simplified to a "constant growth" form:[44]

$$P_0 = \frac{D_1}{k_e - g}$$

where: P_0 = Current price per share;
D_1 = Expected dividend per share in coming year;
k_e = Cost of equity;
g = Investors' long-term growth expectations.

The cost of equity (K_e) can be isolated by rearranging terms:

$$k_e = \frac{D_1}{P_0} + g$$

This constant growth form of the DCF model recognizes that the rate of return to stockholders consists of two parts: 1) dividend yield (D_1/P_0), and 2) growth (g). In other words, investors expect to receive a portion of their total return in the form of current dividends and the remainder through price appreciation.

[44] The constant growth DCF model is dependent on a number of strict assumptions, which in practice are never strictly met. These include a constant growth rate for both dividends and earnings; a stable dividend payout ratio; the discount rate exceeds the growth rate; a constant growth rate for book value and price; a constant earned rate of return on book value; no sales of stock at a price above or below book value; a constant price-earnings ratio; a constant discount rate (*i.e.*, no changes in risk or interest rate levels and a flat yield curve); and all of the above extend to infinity.

Q. How did you define the utility proxy group you used to implement the DCF model?

A. In estimating the cost of equity, the DCF model is typically applied to publicly traded firms engaged in similar business activities. In order to reflect the risks and prospects associated with Idaho Power's electric utility operations, my utility proxy group was composed of those dividend-paying companies included by The Value Line Investment Survey ("Value Line") in its Electric Utilities Industry groups with: (1) S&P corporate credit ratings between "BBB-" and "BBB+", (2) a Value Line Safety Rank of "2" or "3", and (3) a Value Line Financial Strength Rating of "B" to "B++". I excluded three firms that otherwise would have been in the proxy group, but are not appropriate for inclusion because they either do not pay common dividends (El Paso Electric Company) or are in the process of being acquired (Energy East Corporation and Puget Energy, Inc.). These criteria resulted in a proxy group composed of 27 comparable risk utilities. I refer to this group as the "Utility Proxy Group."

Q. Do these criteria provide objective evidence that investors would view the firms in your Utility Proxy Group as risk-comparable?

A. Yes. Credit ratings are assigned by independent rating agencies for the purpose of providing investors with a broad assessment of the creditworthiness of a firm.

Because the rating agencies' evaluation includes virtually all of the factors normally considered important in assessing a firm's relative credit standing, corporate credit ratings provide a broad measure of overall investment risk that is readily available to investors. Widely cited in the investment community and referenced by investors as an objective measure of risk, credit ratings are also frequently used as a primary risk indicator in establishing proxy groups to estimate the cost of equity.

While credit ratings provide the most widely referenced benchmark for investment risks, other quality rankings published by investment advisory services also provide relative assessments of risk that are considered by investors in forming their expectations. Value Line's primary risk indicator is its Safety Rank, which ranges from "1" (Safest) to "5" (Riskiest). This overall risk measure is intended to capture the total risk of a stock, and incorporates elements of stock price stability and financial strength. Given that Value Line is perhaps the most widely available source of investment advisory information, its Safety Rank provides a useful guide to the likely risk perceptions of investors.

The Financial Strength Rating is designed as a guide to overall financial strength and creditworthiness, with the key inputs including financial leverage, business volatility measures, and company size. Value Line's Financial Strength

Ratings range from "A++" (strongest) down to "C" (weakest) in nine steps.

As discussed earlier, Idaho Power is rated "BBB" by S&P, which is identical to the average for the firms in the Utility Proxy Group. Meanwhile, Value Line has assigned IDACORP a Safety Rank of "3" and a Financial Strength Rating of "B+".[45] Based on these criteria, which reflect objective, published indicators that incorporate consideration of a broad spectrum of risks, including financial and business position, relative size, and exposure to company specific factors, investors are likely to regard this group as having comparable risks and prospects.

Q. What steps are required to apply the DCF model?

A. The first step in implementing the constant growth DCF model is to determine the expected dividend yield (D_1/P_0) for the firm in question. This is usually calculated based on an estimate of dividends to be paid in the coming year divided by the current price of the stock. The second, and more controversial, step is to estimate investors' long-term growth expectations (g) for the firm. The final step is to sum the firm's dividend yield and estimated growth rate to arrive at an estimate of its cost of equity.

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[45] As noted earlier, Idaho Power is a wholly-owned subsidiary of IDACORP. Because Value Line's risk indicators apply to publicly traded common stock, I referenced published values for IDACORP in selecting a risk-comparable proxy group.

Q. How was the dividend yield for the Utility Proxy Group determined?

A. Estimates of dividends to be paid by each of these utilities over the next twelve months, obtained from Value Line, served as D_1. This annual dividend was then divided by the corresponding stock price for each utility to arrive at the expected dividend yield. The expected dividends, stock prices, and resulting dividend yields for the firms in the Utility Proxy Group are presented on Exhibit No. 17. As shown there, dividend yields for the firms in the Utility Proxy Group ranged from 1.2 percent to 6.1 percent.

Q. What is the next step in applying the constant growth DCF model?

A. The next step is to evaluate long-term growth expectations, or "*g*", for the firm in question. In constant growth DCF theory, earnings, dividends, book value, and market price are all assumed to grow in lockstep, and the growth horizon of the DCF model is infinite. But implementation of the DCF model is more than just a theoretical exercise; it is an attempt to replicate the mechanism investors used to arrive at observable stock prices. A wide variety of techniques can be used to derive growth rates, but the only "*g*" that matters in applying the DCF model is the value that investors expect.

Q. Are historical growth rates likely to be representative of investors' expectations for utilities?

A. No. If past trends in earnings, dividends, and book value are to be representative of investors' expectations for the future, then the historical conditions giving rise to these growth rates should be expected to continue. That is clearly not the case for utilities, where structural and industry changes have led to declining dividends, earnings pressure, and, in many cases, significant write-offs. While these conditions serve to depress historical growth measures, they are not representative of long-term expectations for the utility industry. Moreover, to the extent historical trends for utilities are meaningful, they are also captured in projected growth rates, since securities analysts also routinely examine and assess the impact and continued relevance (if any) of historical trends.

Q. What are investors most likely to consider in developing their long-term growth expectations?

A. While the DCF model is technically concerned with growth in dividend cash flows, implementation of this DCF model is solely concerned with replicating the forward-looking evaluation of real-world investors. In the case of utilities, dividend growth rates are not likely to provide a meaningful guide to investors' current growth expectations. This is because utilities have significantly altered their dividend policies in response to more accentuated business risks in the industry.[46] As a result of this trend towards a more conservative payout ratio, dividend growth in the utility industry has remained largely stagnant as utilities conserve financial resources to provide a hedge against heightened uncertainties.

As payout ratios for firms in the utility industry trended downward, investors' focus has increasingly shifted from dividends to earnings as a measure of long-term growth. Future trends in earnings, which provide the source for future dividends and ultimately support share prices, play a pivotal role in determining investors' long-term growth expectations. The importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community. As noted in *Finding Reality in Reported Earnings* published by the Association for Investment Management and Research:

> [E]arnings, presumably, are the basis for the investment benefits that we all seek. "Healthy earnings equal healthy investment benefits" seems a logical equation, but earnings are also a scorecard by which we compare companies, a filter through which we assess management, and a crystal ball in which we try to foretell future performance.[47]

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[46] For example, the payout ratio for electric utilities fell from approximately 80 percent historically to on the order of 60 percent. The Value Line Investment Survey (Sep. 15, 1995 at 161, Dec. 28, 2007 at 695).

[47] Association for Investment Management and Research, "Finding Reality in Reported Earnings: An Overview", p. 1 (Dec. 4, 1996).

Value Line's near-term projections and its Timeliness Rank,[48] which is the principal investment rating assigned to each individual stock, are also based primarily on various quantitative analyses of earnings. As Value Line explained:

> The future earnings rank accounts for 65% in the determination of relative price change in the future; the other two variables (current earnings rank and current price rank) explain 35%.[49]

The fact that investment advisory services focus on growth in earnings indicates that the investment community regards this as a superior indicator of future long-term growth. Indeed, "A Study of Financial Analysts: Practice and Theory," published in the *Financial Analysts Journal*, reported the results of a survey conducted to determine what analytical techniques investment analysts actually use.[50] Respondents were asked to rank the relative importance of earnings, dividends, cash flow, and book value in analyzing securities. Of the 297 analysts that responded, only 3 ranked dividends first while 276 ranked it last. The article concluded:

> Earnings and cash flow are considered far more important than book value and dividends.[51]

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[48] The Timeliness Rank presents Value Line's assessment of relative price performance during the next six to twelve months based on a five point scale.

[49] The Value Line Investment Survey, *Subscriber's Guide*, p. 53.

[50] Block, Stanley B., "A Study of Financial Analysts: Practice and Theory", *Financial Analysts Journal* (July/August 1999).

[51] *Id.* at 88.

More recently, the *Financial Analysts Journal* reported the results of a study of the relationship between valuations based on alternative multiples and actual market prices, which concluded, "In all cases studied, earnings dominated operating cash flows and dividends."[52]

Q. What are security analysts currently projecting in the way of growth for the firms in the Utility Proxy Group?

A. The earnings growth projections for each of the firms in the Utility Proxy Group reported by Value Line, Thomson Financial ("Thomson"),[53] and Zacks Investment Research ("Zacks") are displayed on Exhibit No. 17.

Q. How else are investors' expectations of future long-term growth prospects often estimated for use in the constant growth DCF model?

A. Based on the assumptions underlying constant growth theory, conventional applications of the constant growth DCF model often examine the relationship between retained earnings and earned rates of return as an indication of the sustainable growth investors might expect from the reinvestment of earnings within a firm. The sustainable growth rate is calculated by the following formula:

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[52] Liu, Jing, Nissim, Doron, & Thomas, Jacob, "Is Cash Flow King in Valuations?," *Financial Analysts Journal*, Vol. 63, No. 2 (March/April 2007) at 56.

[53] Thomson Financial, an arm of The Thomson Corporation, compiles and publishes consensus securities analyst growth rates under the IBES and First Call brands.

g = br + sv

where: g = investors' expected long-term growth rate;
b = expected retention ratio;
r = expected earned return on equity;
s = percent of common equity expected to be issued annually as new common stock; and,
v = expected equity accretion rate.

Q. What is the purpose of the "sv" term?

A. Under DCF theory, the "sv" factor is a component of the growth rate designed to capture the impact of issuing new common stock at a price above, or below, book value. When a company's stock price is greater than its book value per share, the per-share contribution in excess of book value associated with new stock issues will accrue to the current shareholders. This increase to the book value of existing shareholders leads to higher expected earnings and dividends, with the "sv" factor incorporating this additional growth component.

Q. What growth rate does the earnings retention method suggest for the Utility Proxy Group?

A. The sustainable, "br+sv" growth rates for each firm in the Utility Proxy Group are summarized on Exhibit No. 17, with the underlying details being presented on Exhibit No. 18. For each firm, the expected retention ratio (b) was calculated based on Value Line's projected dividends and earnings per share. Likewise, each firm's expected earned rate of return (r) was computed by dividing projected earnings per share by projected net book value. Because Value Line reports end-of-year book values, an adjustment was incorporated to compute an average rate of return over the year, consistent with the theory underlying this approach to estimating investors' growth expectations. Meanwhile, the percent of common equity expected to be issued annually as new common stock (s) was equal to the product of the projected market-to-book ratio and growth in common shares outstanding, while the equity accretion rate (v) was computed as 1 minus the inverse of the projected market-to-book ratio.

Q. What cost of equity estimates were implied for the Utility Proxy Group using the DCF model?

A. After combining the dividend yields and respective growth projections for each utility, the resulting cost of equity estimates are shown on Exhibit No. 17.

Q. In evaluating the results of the constant growth DCF model, is it appropriate to eliminate cost of equity estimates that fail to meet threshold tests of economic logic?

A. Yes. It is a basic economic principle that investors can be induced to hold more risky assets only if they expect to earn a return to compensate them for their risk bearing. As a result, the rate of return that investors require from a utility's common stock, the most junior and highest risk of its securities, must be considerably higher than the yield offered by senior, long-term debt. Consistent with this principle, the DCF range for the Utility Proxy Group must be adjusted to eliminate cost of equity estimates that fail fundamental tests of economic logic.

Q. Have similar tests been applied by regulators?

A. Yes. The FERC has noted that adjustments are justified where applications of the DCF approach produce illogical results. FERC evaluates DCF results against observable yields on long-term public utility debt and has recognized that it is appropriate to eliminate cost of equity estimates that do not sufficiently exceed this threshold. In a 2000 opinion establishing its current precedent for determining ROEs for electric utilities, for example, FERC concluded:

> An adjustment to this data is appropriate in the case of PG&E's low-end return of 8.42%, which is comparable to the average Moody's "A" grade public utility bond yield of 8.06%, for October 1999. Because investors cannot be expected to purchase stock if debt, which has less risk than stock, yields essentially the same return, this low-end return cannot be considered reliable in this case.[54]

Similarly, in its October 2006 decision in *Kern River Gas Transmission Company*, FERC noted that:

> [T]he 7.31 and 7.32% costs of equity for El Paso and Williams found by the ALJ are only 110 and 122

[54] *Southern California Edison Company*, 92 FERC ¶ 61,070 (2000) at p. 22.

> basis points above that average yield for public utility debt.[55]

FERC upheld the opinion of Staff and the Administrative Law Judge that cost of equity estimates for these two proxy group companies "were too low to be credible."[56]

Q. What does this test of logic imply with respect to the DCF results for the Utility Proxy Group?

A. The average credit rating associated with the firms in the Utility Proxy group is "BBB". Corporate credit ratings of "BBB-", "BBB", and "BBB+" are all considered part of the triple-B rating category, with Moody's monthly yields on triple-B bonds averaging approximately 6.9 percent in May 2008.[57] As highlighted on Exhibit No. 17, eight of the individual equity estimates for the firms in the Utility Proxy Group fell below 8 percent.[58] In light of the risk-return tradeoff principle, it is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock, which is the riskiest of a utility's securities. As a result, these values provide little guidance as to the returns investors require from the common stock of an electric utility.

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[55] *Kern River Gas Transmission Company*, Opinion No. 486, 117 FERC ¶ 61,077 at P 140 & n. 227 (2006).

[56] *Id.*

[57] Moody's Investors Service, *www.CreditTrends.com*.

[58] As highlighted on Exhibit 2, these DCF estimates ranged from 6.2 percent to 7.8 percent.

Q. Do you also recommend excluding cost of equity estimates at the high end of the range of DCF results?

A. Yes. The upper end of the cost of equity range produced by the DCF analysis presented in Exhibit No. 17 was set by a cost of equity estimate of 23.0 percent for Allegheny Energy, with eleven other DCF estimates ranging from 17.1 percent to 22.7 percent. Compared with the balance of the remaining estimates, these results are extreme outliers and should also be excluded in evaluating the results of the DCF model for the Utility Proxy Group. This is also consistent with the threshold adopted by FERC, which established that a 17.7 percent DCF estimate for was "an extreme outlier" and should be disregarded.[59]

Q. What cost of equity is implied by your DCF results for the Utility Proxy Group?

A. As shown on Exhibit No. 17 and summarized in Table 1, below, after eliminating illogical low- and high-end values, application of the constant growth DCF model resulted in the following cost of equity estimates:

TABLE 1
DCF RESULTS - UTILITY PROXY GROUP

Growth Rate	Average Cost of Equity
Value Line	11.7%
IBES	11.6%
Zacks	11.1%
br+sv	9.5%

[59] *ISO New England, Inc.*, 109 FERC ¶ 61,147 at P 205 (2004).

Q. What did you conclude based on the results of the DCF analyses for the Utility Proxy Group?

A. Taken together, and considering the relative strengths and weaknesses associated with the alternative growth measures, I concluded that the constant growth DCF results for the Electric Utility Proxy Group implied a cost of equity of 11.0 percent.

Q. How else can the DCF model be applied to estimate the ROE for Idaho Power?

A. Under the regulatory standards established by *Hope* and *Bluefield*, the salient criteria in establishing a meaningful benchmark to evaluate a fair rate of return is relative risk, not the particular business activity or degree of regulation. Utilities must compete for capital, not just against firms in their own industry, but with other investment opportunities of comparable risk. With regulation taking the place of competitive market forces, required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition. Consistent with this accepted regulatory standard, I also applied the DCF model to a reference group of comparable risk companies in the non-utility sectors of the economy. I refer to this group as the "Non-Utility Proxy Group".

Q. What criteria did you apply to develop the Non-Utility Proxy Group?

A. To reflect investors' risk perceptions in developing the Non-Utility Proxy Group, my assessment of comparable risk relied on three objective benchmarks for the risks associated with common stocks - Value Line's Safety Rank, Financial Strength Rating, and beta. Given that Value Line is perhaps the most widely available source of investment advisory information, its Safety Rank and Financial Strength Rating provide useful guidance regarding the risk perceptions of investors. These objective, published indicators incorporate consideration of a broad spectrum of risks, including financial and business position, relative size, and exposure to company-specific factors.

My comparable risk proxy group was composed of those U.S. companies followed by Value Line that: 1) pay common dividends; 2) have a Safety Rank of "1"; 3) have a Financial Strength Rating of "A" or above; and 4) have beta values of 0.90 or less.[60] Consistent with the development of my Utility Proxy Group, I also eliminated firms with below-investment grade credit ratings. Table 2 compares the Non-

[60] This threshold corresponds to the average betas for the Electric Utility Proxy Group of 0.88.

Utility Proxy Group with the Utility Proxy Group and Idaho Power across four key indicators of investment risk:[61]

TABLE 2
COMPARISON OF RISK INDICATORS

	S&P Credit Rating	Value Line Safety Rank	Value Line Financial Strength	Value Line Beta
Non-Utility Group	A+	1	A+	0.79
Utility Proxy Group	BBB	3	B+	0.88
Idaho Power	BBB	3	B+	0.90

Considered along with S&P's corporate credit ratings, a comparison of these Value Line indicators suggests that the investment risks associated with the Non-Utility Proxy Group are below those of the group of utilities and Idaho Power.

Q. What were the results of your DCF analysis for the Non-Utility Proxy Group?

A. As shown on Exhibit No. 19, I applied the DCF model to the Non-Utility Proxy Group in exactly the same manner described earlier for the Utility Proxy Group.[62] As summarized in Table 3, below, after eliminating illogical low- and high-end values, application of the constant growth DCF model resulted in the following cost of equity estimates:

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[61] Because Idaho Power has no publicly traded common stock, the Value Line risk measures shown reflect those published for its parent, IDACORP. As explained earlier, in my opinion these risk measures are indicative of the risk of Idaho Power.

[62] Exhibit 5 contains the details underlying the calculation of the br+sv growth rates for the Non-Utility Proxy Group.

TABLE 3
DCF RESULTS – NON-UTILITY PROXY GROUP

Growth Rate	Average Cost of Equity
Value Line	12.3%
IBES	12.8%
Zacks	12.5%
br+sv	12.7%

Q. What did you conclude based on the results of the DCF analyses for the Non-Utility Proxy Group?

A. Taken together, I concluded that the constant growth DCF results for the Non-Utility Proxy Group implied a cost of equity of 12.6 percent. As discussed earlier, reference to the Non-Utility Proxy Group is consistent with established regulatory principles and required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition.

Q. Do you believe the DCF model should be relied on exclusively to evaluate a reasonable ROE for the proxy groups or Idaho Power?

A. No. Because the cost of equity is unobservable, no single method should be viewed in isolation. While the DCF model has been routinely relied on in regulatory proceedings as one guide to investors' required return, it is widely recognized that no single method can be regarded as definitive. For example, a publication of the Society of Utility and Financial Analysts (formerly the National Society of Rate of Return Analysts), concluded that:

> Each model requires the exercise of judgment as to the reasonableness of the underlying assumptions of the methodology and on the reasonableness of the proxies used to validate the theory. Each model has its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Each method proceeds from different fundamental premises, most of which cannot be validated empirically. Investors clearly do not subscribe to any singular method, nor does the stock price reflect the application of any one single method by investors.[63]

Moreover, evidence suggests that reliance on the DCF model as a tool for estimating investors' required rate of return has declined outside the regulatory sphere, with the CAPM being "the dominant model for estimating the cost of equity."[64]

C. Capital Asset Pricing Model

Q. Please describe the CAPM.

A. The CAPM is generally considered to be the most widely referenced method for estimating the cost of equity both among academicians and professional practitioners, with the pioneering researchers of this method receiving the Nobel Prize in 1990. The CAPM is a theory of market equilibrium that measures risk using the beta coefficient. Because investors are assumed to be fully diversified, the

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[63] Parcell, David C., "The Cost of Capital – A Practitioner's Guide," *Society of Utility and Regulatory Financial Analysts* (1997) at Part 2, p. 4.

[64] *See e.g.*, Bruner, R.F., Eades, K.M., Harris, R.S., and Higgins, R.C., "Best Practices in Estimating Cost of Capital: Survey and Synthesis," Financial Practice and Education (1998).

relevant risk of an individual asset (*e.g.*, common stock) is its volatility relative to the market as a whole, with beta reflecting the tendency of a stock's price to follow changes in the market. The CAPM is mathematically expressed as:

$$R_j = R_f + \beta_j(R_m - R_f)$$

where: R_j = required rate of return for stock j;
R_f = risk-free rate;
R_m = expected return on the market portfolio; and,
β_j = beta, or systematic risk, for stock j.

Like the DCF model, the CAPM is an *ex-ante*, or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM should be applied using estimates that reflect the expectations of actual investors in the market, not with backward-looking, historical data.

Q. How did you apply the CAPM to estimate the cost of equity?

A. Application of the CAPM to the utility proxy group based on a forward-looking estimate for investors' required rate of return from common stocks is presented on Exhibit No. 21. In order to capture the expectations of today's investors in current capital markets, the expected market rate of return was estimated by conducting a DCF analysis on the dividend paying firms in the S&P 500 Composite Index ("S&P 500").

The dividend yield for each firm was obtained from Value Line, with the growth rate being equal to the average of the earnings growth projections for each firm published by IBES and Value Line, with each firm's dividend yield and growth rate being weighted by its proportionate share of total market value. Based on the weighted average of the projections for the 350 individual firms, current estimates imply an average growth rate over the next five years of 10.6 percent. Combining this average growth rate with a dividend yield of 2.4 percent results in a current cost of equity estimate for the market as a whole of approximately 12.9 percent. Subtracting a 4.6 percent risk-free rate based on the average yield on 20-year Treasury bonds for May 2008 produced a market equity risk premium of 8.3 percent. As shown on Exhibit No. 21, multiplying this risk premium by the average Value Line beta of 0.88 for the Utility Proxy Group, and then adding the resulting 7.3 percent risk premium to the average long-term Treasury bond yield, indicated an ROE of approximately 11.9 percent.

Q. What cost of equity was indicated for the Non-Utility Proxy Group based on this forward-looking application of the CAPM?

A. As shown on Exhibit No. 22, applying the forward-looking CAPM approach to the firms in the Non-Utility Proxy Group implied a cost of equity estimate of 11.2 percent.

Q. What other CAPM analyses did you conduct to estimate the cost of equity?

A. In addition, because it is frequently referenced in regulatory proceedings, I also applied the CAPM using risk premiums based on historical realized rates of return published by Ibbotson Associates (now Morningstar). Reference to historical data represents one way to apply the CAPM, but these realized rates of return reflect, at best, an indirect estimate of investors' current requirements. As a result, forward-looking applications of the CAPM that look directly at investors' expectations in the capital markets are apt to provide a more meaningful guide to investors' required rate of return.

Q. What CAPM cost of equity is produced based on historical realized rates of return for stocks and long-term government bonds?

A. Application of the CAPM to the firms in the utility and non-utility proxy groups using risk premiums based on historical realized rates of return published by Ibbotson Associates is presented on Exhibits Nos. 23 and 24, respectively. As shown there, this historical CAPM approach implied a cost of equity of 10.8 percent for the Utility Proxy Group and 10.2 percent for the firms in the Non-Utility Proxy Group.

D. Comparable Earnings Method

Q. What other analyses did you conduct to estimate the cost of equity?

A. As I noted earlier, I also evaluated the cost of equity using the comparable earnings method. Reference to rates of return available from alternative investments of comparable risk can provide an important benchmark in assessing the return necessary to assure confidence in the financial integrity of a firm and its ability to attract capital. This comparable earnings approach is consistent with the economic underpinnings for a fair rate of return established by the United States Supreme Court and has been traditionally relied on by the IPUC. Moreover, it avoids the complexities and limitations of capital market methods and instead focuses on the returns earned on book equity, which are readily available to investors.

Q. What rates of return on equity are indicated for utilities based on this approach?

A. With respect to expectations for electric utilities generally, Value Line reports that its analysts anticipate an average rate of return on common equity for the electric utility industry of 11.5 percent in 2008 and 2009 and 13.0 percent over its three-to-five year forecast horizon.[65] Meanwhile, Value Line expects that natural gas

[65] The Value Line Investment Survey at 150 (May 30, 2008).

distribution utilities will earn an average rate of return on common equity of 11.5 percent in 2008 and 12.0 percent in 2009, and 12.5 percent over the years 2011-2013.[66]

For the firms in the Utility Proxy Group specifically, the returns on common equity projected by Value Line over its three-to-five year forecast horizon are shown on Exhibit No. 25. Consistent with the rational underlying the development of the br+sv growth rates discussed earlier, these year-end values were converted to average returns using the same adjustment factor developed in Exhibit No. 18. As shown on Exhibit No. 25, after eliminating extreme outliers, Value Line's projections suggested an average ROE of 11.1 percent.

Q. What return on equity is indicated by the results of the comparable earnings approach?

A. Based on the results discussed above, I concluded that the comparable earnings approach implies a fair rate of return on equity of at least 11.1 percent.

E. Summary of Results

Q. Please summarize the results of your quantitative analyses.

A. The cost of equity estimates implied by my quantitative analyses are summarized in Table 4 below:

[66] The Value Line Investment Survey at 446 (Mar. 14, 2008).

TABLE 4
SUMMARY OF QUANTITATIVE RESULTS

Method	Utility	Non-Utility
DCF	11.0%	12.6%
CAPM		
Forward-Looking	11.9%	11.2%
Historical	10.8%	10.2%
Comparable Earnings	11.1%	

F. Flotation Costs

Q. What other considerations are relevant in setting the return on equity for a utility?

A. The common equity used to finance the investment in utility assets is provided from either the sale of stock in the capital markets or from retained earnings not paid out as dividends. When equity is raised through the sale of common stock, there are costs associated with "floating" the new equity securities. These flotation costs include services such as legal, accounting, and printing, as well as the fees and discounts paid to compensate brokers for selling the stock to the public. Also, some argue that the "market pressure" from the additional supply of common stock and other market factors may further reduce the amount of funds a utility nets when it issues common equity.

Q. Is there an established mechanism for a utility to recognize equity issuance costs?

A. No. While debt flotation costs are recorded on the books of the utility, amortized over the life of the issue, and thus increase the effective cost of debt capital, there is no similar accounting treatment to ensure that equity flotation costs are recorded and ultimately recognized. Alternatively, no rate of return is authorized on flotation costs necessarily incurred to obtain a portion of the equity capital used to finance plant. In other words, equity flotation costs are not included in a utility's rate base because neither that portion of the gross proceeds from the sale of common stock used to pay flotation costs is available to invest in plant and equipment, nor are flotation costs capitalized as an intangible asset. Unless some provision is made to recognize these issuance costs, a utility's revenue requirements will not fully reflect all of the costs incurred for the use of investors' funds. Because there is no accounting convention to accumulate the flotation costs associated with equity issues, they must be accounted for indirectly, with an upward adjustment to the cost of equity being the most logical mechanism.

Q. What is the magnitude of the adjustment to the "bare bones" cost of equity to account for issuance costs?

A. There are any number of ways in which a flotation cost adjustment can be calculated, and the adjustment can range from just a few basis points to more than a full percent. One of the most common methods used to account for flotation costs in regulatory proceedings is to apply an average flotation-cost percentage to a utility's dividend yield. Based on a review of the finance literature, *Regulatory Finance: Utilities' Cost of Capital* concluded:

> The flotation cost allowance requires an estimated adjustment to the return on equity of approximately 5% to 10%, depending on the size and risk of the issue.[67]

Alternatively, a study of data from Morgan Stanley regarding issuance costs associated with utility common stock issuances suggests an average flotation cost percentage of 3.6 percent.[68] Applying these expense percentages to a representative dividend yield for a utility of 3.9 percent implies a flotation cost adjustment on the order of 14 to 39 basis points.

Q. Has the IPUC Staff previously considered flotation costs in establishing a fair ROE for Idaho Power?

A. Yes. For example, in Case No. IPC-E-07-8, IPUC Staff witness Terri Carlock noted that she had adjusted her DCF analysis to incorporate an allowance for flotation costs.[69] While issuance costs are a legitimate consideration in setting the return on equity for a utility,

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[67] Roger A. Morin, *Regulatory Finance: Utilities' Cost of Capital*, 1994, at 166.

[68] *Application of Yankee Gas Services Company for a Rate Increase*, DPUC Docket No. 04-06-01, Direct Testimony of George J. Eckenroth (Jul. 2, 2004) at Exhibit GJE-11.1. Updating the results presented by Mr. Eckenroth through April 2005 also resulted in an average flotation cost percentage of 3.6 percent.

[69] Case No. IPC-E-07-8, *Direct Testimony of Terri Carlock* at 10 (Dec. 10, 2007).

a specific adjustment for flotation costs was not included in defining my recommended ROE range.

IV. RETURN ON EQUITY FOR IDAHO POWER COMPANY

Q. What is the purpose of this section?

A. In addition to presenting the conclusions of my evaluation of a fair rate of return on equity for Idaho Power, this section also discusses the relationship between ROE and preservation of a utility's financial integrity and the ability to attract capital under reasonable terms on a sustainable basis.

A. Implications for Financial Integrity

Q. Why is it important to allow Idaho Power an adequate ROE?

A. Given the social and economic importance of the utility industry, it is essential to maintain reliable and economical service to all consumers. While Idaho Power remains committed to deliver reliable service, a utility's ability to fulfill its mandate can be compromised if it lacks the necessary financial wherewithal. Coupled with the ongoing potential for energy market volatility, Idaho Power's exposure to variations in hydroelectric generation and plans for significant infrastructure investment pose a number of potential challenges that might require the relatively swift commitment of significant capital resources in order to maintain the high level of service that customers have come to expect.

As documented earlier, the major rating agencies have warned of exposure to uncertainties associated with political and regulatory developments, especially in view of the potential for high and volatile commodity costs in competitive energy markets. Investors understand how swiftly unforeseen circumstances can lead to deterioration in a utility's financial condition, and stakeholders have discovered first hand how difficult and complex it can be to remedy the situation after the fact. For a utility with an obligation to provide reliable service, investors' increased reticence to supply additional capital during times of crisis highlights the necessity of preserving the flexibility necessary to overcome periods of adverse capital market conditions.

Q. What role does regulation play in ensuring Idaho Power's access to capital?

A. Considering investors' heightened awareness of the risks associated with the utility industry and the damage that results when a utility's financial flexibility is compromised, supportive regulation remains crucial to Idaho Power's access to capital. Investors recognize that regulation has its own risks, and that constructive regulation is a key ingredient in supporting utility credit ratings and financial integrity, particularly during times of adverse conditions. S&P concluded, "The political atmosphere will remain highly charged, fostering uncertainty."[70] Moody's echoed these sentiments, noting that "regulatory relationships are becoming more important" in an era of broadly rising costs and uncertainties,[71] and concluding:

> [T]here are concerns arising from the sector's sizeable infrastructure investment plans in the face of an environment of steadily rising operating costs. Combined, these costs and investments can create a continuous need for regulatory rate relief, which in turn can increase the likelihood for political and/or regulatory intervention.[72]

The rapid rise in wholesale energy prices has heightened investor concerns over the implications for regulatory uncertainty. The Wall Street Journal reported in May 2008 that escalating fuel costs were leading to soaring utility bills across the nation, raising the specter that social pressures could impact the outcome of regulatory proceedings.[73] S&P noted that, while timely cost recovery was paramount to maintaining credit quality in the utility sector, an "environment of rising customer tariffs, coupled

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[70] Standard & Poor's Corporation, "Top Ten Credit Issues Facing U.S. Utilities," *RatingsDirect* (Jan. 29, 2007).

[71] Moody's Investors Service, "Regulatory Pressures Increase for U.S. Electric Utilities," *Special Comment* (March 2007).

[72] Moody's Investors Service, "Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector," *Special Comment* (Aug. 2007).

[73] Smith, Rebecca, "Expect a Jolt When Opening The Electric Bill," Wall Street Journal at D1 (May 7, 2008).

with a sluggish economy, portend a difficult regulatory environment in coming years."[74]

Q. What danger does an inadequate rate of return pose to Idaho Power?

A. Given the pressure on Idaho Power's financial metrics and its declining credit standing, which is exemplified by the negative outlook assigned by Moody's and Fitch, the perception of a lack of regulatory support would almost certainly lead to further downgrades. As Moody's concluded, "A key consideration in order for [Idaho Power] to stabilize its rating outlook and maintain its Baa1 senior unsecured rating will be the extent to which the IPUC is supportive in any future regulatory filings."[75]

At the same time, Idaho Power's plans include significant plant investment to ensure that the energy needs of its service territory are met in a reliable and cost-effective manner. Fitch noted that '[m]eaningful price increases will be required to recover planned capital expenditures to meet infrastructure and growth requirements,[76] while S&P cited "[r]egulatory challenges in meeting rising costs and a large capital expenditure

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[74] Standard & Poor's Corporation, "Top 10 U.S. Electric Utility Credit Issues For 2008 And Beyond," *RatingsDirect* (Jan. 28, 2008).

[75] Moody's Investors Service, "Credit Opinion: Idaho Power Company," *Global Credit Research* (June 4, 2008).

[76] Fitch Ratings, Ltd., "Idaho Power Company," *Global Power U.S. and Canada Credit Analysis* (Apr. 10, 2008).

program" as a key risk exposure.[77] While providing the infrastructure necessary to meet the energy needs of customers is certainly desirable, it imposes additional financial responsibilities on Idaho Power. To continue to meet these challenges successfully and economically, it is crucial that Idaho Power receive adequate support to buttress its credit standing.

Q. Do customers benefit by enhancing the utility's financial flexibility?

A. Yes. While providing an ROE that is sufficient to maintain Idaho Power's ability to attract capital, even in times of financial and market stress, is consistent with the economic requirements embodied in the Supreme Court's *Hope* and *Bluefield* decisions, it is also in customers' best interests. Ultimately, it is customers and the service area economy that enjoy the benefits that come from ensuring that the utility has the financial wherewithal to take whatever actions are required to ensure reliable service. By the same token, customers also bear a significant burden when the ability of the utility to attract necessary capital is impaired and service quality is compromised.

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[77] Standard & Poor's Corporation, "Idaho Power Co.," *RatingsDirect* (Feb. 1, 2008).

B. Capital Structure

Q. Is an evaluation of the capital structure maintained by a utility relevant in assessing its return on equity?

A. Yes. Other things equal, a higher debt ratio, or lower common equity ratio, translates into increased financial risk for all investors. A greater amount of debt means more investors have a senior claim on available cash flow, thereby reducing the certainty that each will receive his contractual payments. This increases the risks to which lenders are exposed, and they require correspondingly higher rates of interest. From common shareholders' standpoint, a higher debt ratio means that there are proportionately more investors ahead of them, thereby increasing the uncertainty as to the amount of cash flow, if any, that will remain.

Q. What common equity ratio is implicit in Idaho Power's requested capital structure?

A. Idaho Power's capital structure is presented in the testimony of Mr. Steve Keen. As summarized in his testimony, the common equity ratio used to compute Idaho Power's overall rate of return was approximately 49 percent in this filing.

Q. What was the average capitalization maintained by the Utility Proxy Group?

A. As shown on Exhibit No. 26, for the firms in the Utility Proxy Group, common equity ratios at December 31, 2007 ranged from 13.8 percent to 57.9 percent and averaged 43.3 percent. Value Line expects that the average common equity ratio for the proxy group of electric utilities will average 47.6 percent over the next three to five years, with the individual common equity ratios ranging from 29.0 percent to 59.5 percent.

Q. What implication do the uncertainties facing the utility industry have for the capital structures maintained by electric utilities?

A. As discussed earlier, utilities are facing energy market volatility, rising cost structures, the need to finance significant capital investment plans, uncertainties over accommodating future environmental mandates, and ongoing regulatory risks. Coupled with a decline in credit quality, these considerations warrant a stronger balance sheet to deal with an increasingly uncertain and competitive market. A more conservative financial profile, in the form of a higher common equity ratio, is consistent with increasing uncertainties and the need to maintain the continuous access to capital that is required to fund operations and necessary system investment, even during times of adverse capital market conditions.

Moody's has warned investors of the risks associated with debt leverage and fixed obligations and advised utilities not to squander the opportunity to strengthen the balance sheet as a buffer against future uncertainties.[78] Moody's recently noted that, absent a stronger equity cushion, utilities would be faced with lower credit ratings in the face of rising business and operating risks:

> There are significant negative trends developing over the longer-term horizon. This developing negative concern primarily relates to our view that the sector's overall business and operating risks are rising - at an increasingly fast pace - but that the overall financial profile remains relatively steady. A rising risk profile accompanied by a relatively stable balance sheet profile would ultimately result in credit quality deterioration.[79]

This is especially the case for electric utilities that are exposed to potential significant fluctuations in power supply costs, such as Idaho Power.

Q. What other factors do investors consider in their assessment of a company's capital structure?

A. Because power purchase agreements ("PPAs") and other contractual commitments typically obligate the utility to make specified minimum payments akin to those associated with traditional debt financing, investors consider a portion of these obligations as debt in evaluating total financial risks. Similarly, when a utility enters into a mandated PPA with a Qualifying Facility under PURPA, the

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[78] Moody's Investors Service, "Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector," *Special Comment* (Aug. 2007).

[79] Moody's Investors Service, "U.S. Electric Utility Sector," *Industry Outlook* (Jan. 2008).

fixed charges associated with the contract increase the utility's financial risk in the same way that long-term debt and other financial obligations increase financial leverage.

Reflecting the longstanding perception of investors that the fixed obligations associated with off-balance sheet obligations diminish a utility's creditworthiness and financial flexibility, the implications of these commitments have been repeatedly cited by major bond rating agencies in connection with assessments of utility financial risks. For example, in explaining its evaluation of the credit implications of off-balance sheet obligations, S&P affirmed its position that such agreements give rise to "debt equivalents" and that the increased financial risk must be considered in evaluating a utility's credit risks.[80]

Q. What did you conclude with respect to the Company's capital structure?

A. Based on my evaluation, I concluded that Idaho Power's requested capital structure represents a reasonable mix of capital sources from which to calculate the Company's overall rate of return. Idaho Power's requested common equity ratio of approximately 49 percent is consistent with the range of capitalizations implied for the Utility Proxy

[80] Standard & Poor's Corporation, "Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements," *RatingsDirect* (May 7, 2007).

Group based on year-end 2007 data and Value Line's Line's near-term projections.

While industry averages provide one benchmark for comparison, each firm must select its capitalization based on the risks and prospects it faces, as well its specific needs to access the capital markets. A public utility with an obligation to serve must maintain ready access to capital under reasonable terms so that it can meet the service requirements of its customers. The need for access becomes even more important when the company has capital requirements over a period of years, and financing must be continuously available, even during unfavorable capital market conditions.

The decline in Idaho Power's credit standing and the heightened uncertainty associated with energy market volatility magnifies the importance of preserving financial flexibility. Idaho Power's capital structure reflects the Company's ongoing efforts to support its financial integrity and maintain access to capital on reasonable terms. As indicated earlier, the challenges posed by significant capital requirements, volatile energy prices, and reliance on hydro generation and wholesale markets magnifies the importance of preserving financial flexibility. The rating agencies have observed that Idaho Power's financial metrics have been under pressure, and utilities with higher leverage may be foreclosed from additional borrowing, especially during times of stress. In this regard, Idaho Power's equity ratio reflects the challenges posed by its resource mix, as well as the burden of significant capital spending requirements.

C. <u>Return on Equity Recommendation</u>

Q. Please summarize the results of your analyses.

A. Reflecting the fact that investors' required ROE is unobservable and no single method should be viewed in isolation, I considered the results of both the DCF and CAPM methods and evaluated comparable earned rates of return expected for utilities. In order to reflect the risks and prospects associated with Idaho Power's jurisdictional electric utility operations, my analyses focused on a proxy group of twenty-seven comparable risk electric utilities. Consistent with the fact that utilities must compete for capital with firms outside their own industry, I also referenced a proxy group of comparable risk companies in the non-utility sectors of the economy.

My application of the constant growth DCF model considered three alternative growth measures based on projected earnings growth, as well as the sustainable, "br+sv" growth rate for each firm in the respective proxy groups. In addition, I evaluated the reasonableness of the resulting DCF estimates and eliminated low- and high-end outliers that failed to meet threshold tests of economic logic. My CAPM analyses focused on forward-looking data that best reflects the underlying assumptions of this approach, as well as considering historical risk premiums. The results of my alternative analyses were summarized earlier in Table 4, which is reproduced below:

TABLE 4
SUMMARY OF QUANTITATIVE RESULTS

Method	Utility	Non-Utility
DCF	11.0%	12.6%
CAPM		
Forward-Looking	11.9%	11.2%
Historical	10.8%	10.2%
Comparable Earnings	11.1%	

Based on my assessment of the relative strengths and weaknesses inherent in each method, and conservatively giving less emphasis to the upper-most end of the range of results, I concluded that the cost of equity indicated by my analyses is in the 10.8 percent to 11.8 percent range.

Q. What then is your conclusion as to a fair ROE range for Idaho Power?

A. In evaluating the rate of return for Idaho Power, it is important to consider investors' continued focus on the unsettled conditions in restructured wholesale energy markets, the Company's ongoing exposure to these markets to meet a portion of its energy supply, as well as other risks associated with the utility industry, such as heightened exposure to regulatory uncertainties.

As explained above, I concluded that the fair rate of return on equity range was 10.8 percent to 11.8 percent. Considering capital market expectations, the potential uncertainties faced by Idaho Power, the Company's unique exposure to fluctuations in hydroelectric generation, and the economic requirements necessary to maintain financial integrity and support additional capital investment even under adverse circumstances, it is my opinion that this represents a fair and reasonable ROE range for Idaho Power. While this "bare-bones" cost of equity range does not consider issuance costs, a flotation cost adjustment is properly considered in establishing an allowed ROE for Idaho Power from within this range.

Q. Does this conclude your pre-filed direct testimony?

A. Yes.

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Summary of Qualifications

Ph.D. in economics and finance; Chartered Financial Analyst (CFA®) designation; extensive expert witness testimony before courts, alternative dispute resolution panels, regulatory agencies and legislative committees; lectured in executive education programs around the world on ethics, investment analysis, and regulation; undergraduate and graduate teaching in business and economics; appointed to leadership positions in government, industry, academia, and the military.

Employment

Principal,
FINCAP, Inc.
(Sep. 1979 to present)

Financial, economic and policy consulting to business and government. Perform business and public policy research, cost/benefit analyses and financial modeling, valuation of businesses (over 150 entities valued), estimation of damages, statistical and industry studies. Provide strategy advice and educational services in public and private sectors, and serve as expert witness before regulatory agencies, legislative committees, arbitration panels, and courts.

Director, Economic Research Division,
Public Utility Commission of Texas
(Dec. 1977 to Aug. 1979)

Responsible for research and testimony preparation on rate of return, rate structure, and econometric analysis dealing with energy, telecommunications, water and sewer utilities. Testified in major rate cases and appeared before legislative committees and served as Chief Economist for agency. Administered state and federal grant funds. Communicated frequently with political leaders and representatives from consumer groups, media, and investment community.

Manager, Financial Education,
International Paper Company
New York City
(Feb. 1977 to Nov. 1977)

Directed corporate education programs in accounting, finance, and economics. Developed course materials, recruited and trained instructors, liaison within the company and with academic institutions. Prepared operating budget and designed financial controls for corporate professional development program.

Lecturer in Finance,
The University of Texas at Austin
(Sep. 1979 to May 1981)
Assistant Professor of Finance,
(Sep. 1975 to May 1977)

Taught graduate and undergraduate courses in financial management and investment theory. Conducted research in business and public policy. Named Outstanding Graduate Business Professor and received various administrative appointments.

Assistant Professor of Business,
University of North Carolina at Chapel Hill
(Sep. 1972 to Jul. 1975)

Taught in BBA, MBA, and Ph.D. programs. Created project course in finance, Financial Management for Women, and participated in developing Small Business Management sequence. Organized the North Carolina Institute for Investment Research, a group of financial institutions that supported academic research. Faculty advisor to the Media Board, which funds student publications and broadcast stations.

Education

Ph.D., Economics and Finance,
University of North Carolina at Chapel Hill
(Jan. 1969 to Aug. 1972)

Elective courses included financial management, public finance, monetary theory, and econometrics. Awarded the Stonier Fellowship by the American Bankers' Association and University Teaching Fellowship. Taught statistics, macroeconomics, and microeconomics.

Dissertation: *The Geometric Mean Strategy as a Theory of Multiperiod Portfolio Choice*

B.A., Economics,
Emory University, Atlanta, Georgia
(Sep. 1961 to Jun. 1965)

Active in extracurricular activities, president of the Barkley Forum (debate team), Emory Religious Association, and Delta Tau Delta chapter. Individual awards and team championships at national collegiate debate tournaments.

Professional Associations

Received Chartered Financial Analyst (CFA) designation in 1977; Vice President for Membership, Financial Management Association; President, Austin Chapter of Planning Executives Institute; Board of Directors, North Carolina Society of Financial Analysts; Candidate Curriculum Committee, Association for Investment Management and Research; Executive Committee of Southern Finance Association; Vice Chair, Staff Subcommittee on Economics and National Association of Regulatory Utility Commissioners (NARUC); Appointed to NARUC Technical Subcommittee on the National Energy Act.

Teaching in Executive Education Programs

University-Sponsored Programs: Central Michigan University, Duke University, Louisiana State University, National Defense University, National University of Singapore, Texas A&M University, University of Kansas, University of North Carolina, University of Texas.

Business and Government-Sponsored Programs: Advanced Seminar on Earnings Regulation, American Public Welfare Association, Association for Investment Management and Research, Congressional Fellows Program, Cost of Capital Workshop, Electricity Consumers Resource Council, Financial Analysts Association of Indonesia, Financial Analysts Review, Financial Analysts Seminar at Northwestern University, Governor's Executive Development Program of Texas, Louisiana Association of Business and Industry, National Association of Purchasing Management, National Association of Tire Dealers, Planning Executives Institute, School of Banking of the South, State of Wisconsin Investment Board, Stock Exchange of Thailand, Texas Association of State Sponsored Computer Centers, Texas Bankers' Association, Texas Bar Association, Texas Savings and Loan League, Texas Society of CPAs, Tokyo Association of Foreign Banks, Union Bank of Switzerland, U.S. Department of State, U.S. Navy, U.S. Veterans Administration, in addition to Texas state agencies and major corporations.

Presented papers for Mills B. Lane Lecture Series at the University of Georgia and Heubner Lectures at the University of Pennsylvania. Taught graduate courses in finance and economics in evening program at St. Edward's University in Austin from January 1979 through 1998.

Expert Witness Testimony

Testified in over 260 cases before regulatory agencies addressing cost of capital, regulatory policy, rate design, and other economic and financial issues.

Federal Agencies: Federal Communications Commission, Federal Energy Regulatory Commission, Surface Transportation Board, Interstate Commerce Commission, and the Canadian Radio-Television and Telecommunications Commission.

State Regulatory Agencies: Alaska, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Idaho, Illinois, Indiana, Kansas, Maryland, Michigan, Missouri, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Virginia, Washington, West Virginia, Wisconsin, and Wyoming.

Testified in 42 cases before federal and state courts, arbitration panels, and alternative dispute tribunals (86 depositions given) regarding damages, valuation, antitrust liability, fiduciary duties, and other economic and financial issues.

Board Positions and Other Professional Activities

Audit Committee and Outside Director, Georgia System Operations Corporation (electric system operator for member-owned electric cooperatives in Georgia); Chairman, Board of Print Depot, Inc. and FINCAP, Inc.; Co-chair, Synchronous Interconnection Committee, appointed by Public Utility Commission of Texas and approved by governor; Appointed by Hays County Commission to Citizens Advisory Committee of Habitat Conservation Plan, Operator of AAA Ranch, a certified organic producer of agricultural products; Appointed to Organic Livestock Advisory Committee by

Texas Agricultural Commissioner Susan Combs; Appointed by Texas Railroad Commissioners to study group for *The UP/SP Merger: An Assessment of the Impacts on the State of Texas;* Appointed by Hawaii Public Utilities Commission to team reviewing affiliate relationships of Hawaiian Electric Industries; Chairman, Energy Task Force, Greater Austin-San Antonio Corridor Council; Consultant to Public Utility Commission of Texas on cogeneration policy and other matters; Consultant to Public Service Commission of New Mexico on cogeneration policy; Evaluator of Energy Research Grant Proposals for Texas Higher Education Coordinating Board.

Community Activities

Board Member, Sustainable Food Center; Chair, Board of Deacons, Finance Committee, and Elder, Central Presbyterian Church of Austin; Founding Member, Orange-Chatham County (N.C.) Legal Aid Screening Committee.

Military

Captain, U.S. Naval Reserve (retired after 28 years service); Commanding Officer, Naval Special Warfare Engineering Support Unit; Officer-in-charge of SWIFT patrol boat in Vietnam; Enlisted service as weather analyst (advanced to second class petty officer).

Bibliography

Monographs

Ethics and the Investment Professional (video, workbook, and instructor's guide) and *Ethics Challenge Today* (video), Association for Investment Management and Research (1995)

"Definition of Industry Ethics and Development of a Code" and "Applying Ethics in the Real World," in *Good Ethics: The Essential Element of a Firm's Success*, Association for Investment Management and Research (1994)

"On the Use of Security Analysts' Growth Projections in the DCF Model," with Bruce H. Fairchild in *Earnings Regulation Under Inflation*, J. R. Foster and S. R. Holmberg, eds. Institute for Study of Regulation (1982)

An Examination of the Concept of Using Relative Customer Class Risk to Set Target Rates of Return in Electric Cost-of-Service Studies, with Bruce H. Fairchild, Electricity Consumers Resource Council (ELCON) (1981); portions reprinted in *Public Utilities Fortnightly* (Nov. 11, 1982)

"Usefulness of Current Values to Investors and Creditors," *Research Study on Current-Value Accounting Measurements and Utility*, George M. Scott, ed., Touche Ross Foundation (1978)

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Articles

"Should Analysts Own the Stocks they Cover?" *The Financial Journalist*, (March 2002)

"Liquidity, Exchange Listing, and Common Stock Performance," with John C. Groth and Kerry Cooper, *Journal of Economics and Business* (Spring 1985); reprinted by National Association of Security Dealers

"The Energy Crisis and the Homeowner: The Grief Process," *Texas Business Review* (Jan.–Feb. 1980); reprinted in *The Energy Picture: Problems and Prospects*, J. E. Pluta, ed., Bureau of Business Research (1980)

"Use of IFPS at the Public Utility Commission of Texas," *Proceedings of the IFPS Users Group Annual Meeting* (1979)

"Production Capacity Allocation: Conversion, CWIP, and One-Armed Economics," *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"Some Thoughts on the Rate of Return to Public Utility Companies," with Bruce H. Fairchild in *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"A New Capital Budgeting Measure: The Integration of Time, Liquidity, and Uncertainty," with David Cordell in *Proceedings of the Southwestern Finance Association* (1977)

"Usefulness of Current Values to Investors and Creditors," in *Inflation Accounting/Indexing and Stock Behavior* (1977)

"Consumer Expectations and the Economy," *Texas Business Review* (Nov. 1976)

"Portfolio Performance Evaluation and Long-run Capital Growth," with Henry A. Latané in *Proceedings of the Eastern Finance Association* (1973)

Book reviews in *Journal of Finance* and *Financial Review*. Abstracts for *CFA Digest*. Articles in *Carolina Financial Times*.

Selected Papers and Presentations

"The Who, What, When, How, and Why of Ethics", San Antonio Financial Analysts Society (Jan. 16, 2002). Similar presentation given to the Austin Society of Financial Analysts (Jan. 17, 2002)

"Ethics for Financial Analysts," Sponsored by Canadian Council of Financial Analysts: delivered in Calgary, Edmonton, Regina, and Winnipeg, June 1997. Similar presentations given to Austin Society of Financial Analysts (Mar. 1994), San Antonio Society of Financial Analysts (Nov. 1985), and St. Louis Society of Financial Analysts (Feb. 1986)

"Cost of Capital for Multi-Divisional Corporations," Financial Management Association, New Orleans, Louisiana (Oct. 1996)

"Ethics and the Treasury Function," Government Treasurers Organization of Texas, Corpus Christi, Texas (Jun. 1996)

"A Cooperative Future," Iowa Association of Electric Cooperatives, Des Moines (December 1995). Similar presentations given to National G & T Conference, Irving, Texas (June 1995), Kentucky Association of Electric Cooperatives Annual Meeting, Louisville (Nov. 1994), Virginia, Maryland, and Delaware Association of Electric Cooperatives Annual Meeting, Richmond (July 1994), and Carolina Electric Cooperatives Annual Meeting, Raleigh (Mar. 1994)

"Information Superhighway Warnings: Speed Bumps on Wall Street and Detours from the Economy," Texas Society of Certified Public Accountants Natural Gas, Telecommunications and Electric Industries Conference, Austin (Apr. 1995)

"Economic/Wall Street Outlook," Carolinas Council of the Institute of Management Accountants, Myrtle Beach, South Carolina (May 1994). Similar presentation given to Bell Operating Company Accounting Witness Conference, Santa Fe, New Mexico (Apr. 1993)

"Regulatory Developments in Telecommunications," Regional Holding Company Financial and Accounting Conference, San Antonio (Sep. 1993)

"Estimating the Cost of Capital During the 1990s: Issues and Directions," The National Society of Rate of Return Analysts, Washington, D.C. (May 1992)

"Making Utility Regulation Work at the Public Utility Commission of Texas," Center for Legal and Regulatory Studies, University of Texas, Austin (June 1991)

"Can Regulation Compete for the Hearts and Minds of Industrial Customers," Emerging Issues of Competition in the Electric Utility Industry Conference, Austin (May 1988)

"The Role of Utilities in Fostering New Energy Technologies," Emerging Energy Technologies in Texas Conference, Austin (Mar. 1988)

"The Regulators' Perspective," Bellcore Economic Analysis Conference, San Antonio (Nov. 1987)

"Public Utility Commissions and the Nuclear Plant Contractor," Construction Litigation Superconference, Laguna Beach, California (Dec. 1986)

"Development of Cogeneration Policies in Texas," University of Georgia Fifth Annual Public Utilities Conference, Atlanta (Sep. 1985)

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"Discounted Cash Life: A New Measure of the Time Dimension in Capital Budgeting," with David Cordell, Southern Finance Association, New Orleans (Nov. 1978)

"The Relative Value of Statistics of Ex Post Common Stock Distributions to Explain Variance," with Charles G. Martin, Southern Finance Association, Atlanta (Nov. 1977)

"An ANOVA Representation of Common Stock Returns as a Framework for the Allocation of Portfolio Management Effort," with Charles G. Martin, Financial Management Association, Montreal (Oct. 1976)

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"An Optimal Approach to the Finance Decision," with Henry A. Latané, Southern Finance Association, Atlanta (Nov. 1974)

"A Pragmatic Approach to the Capital Structure Decision Based on Long-Run Growth," with Henry A. Latané, Financial Management Association, San Diego (Oct. 1974)

"Multi-period Wealth Distributions and Portfolio Theory," Southern Finance Association, Houston (Nov. 1973)

"Growth Rates, Expected Returns, and Variance in Portfolio Selection and Performance Evaluation," with Henry A. Latané, Econometric Society, Oslo, Norway (Aug. 1973)

CONSTANT GROWTH DCF MODEL

Exhibit 17
Page 1 of 1

UTILITY PROXY GROUP

		(a)	(a)		(b)	(c)	(d)	(e)	(f)	(f)	(f)	(f)
		Dividend Yield			Growth Rates				Cost of Equity Estimates			
	Company	Price	Dividends	Yield	V Line	IBES	Zacks	br+sv	V Line	IBES	Zacks	br+sv
1	Allegheny Energy	$ 54.25	$ 0.65	1.2%	10.5%	21.5%	21.8%	8.1%	11.7%	22.7%	23.0%	9.3%
2	American Elec Pwr	$ 43.86	$ 1.70	3.9%	6.0%	6.7%	5.4%	5.4%	9.9%	10.6%	9.3%	9.3%
3	Avista Corp.	$ 21.19	$ 0.69	3.3%	9.0%	4.5%	5.0%	3.0%	12.3%	7.8%	8.3%	6.2%
4	Black Hills Corp.	$ 35.62	$ 1.42	4.0%	4.5%	6.0%	6.5%	4.7%	8.5%	10.0%	10.5%	8.7%
5	CenterPoint Energy	$ 16.03	$ 0.74	4.6%	6.0%	12.5%	9.0%	8.5%	10.6%	17.1%	13.6%	13.1%
6	Cleco Corp.	$ 24.96	$ 0.90	3.6%	7.5%	14.0%	9.5%	4.4%	11.1%	17.6%	13.1%	8.0%
7	CMS Energy	$ 15.43	$ 0.40	2.6%	11.5%	9.2%	10.5%	4.4%	14.1%	11.8%	13.1%	7.0%
8	DPL, Inc.	$ 28.25	$ 1.12	4.0%	11.0%	9.2%	8.0%	8.2%	15.0%	13.2%	12.0%	12.2%
9	DTE Energy Co.	$ 43.82	$ 2.12	4.8%	4.5%	5.5%	6.3%	3.5%	9.3%	10.3%	11.1%	8.3%
10	Edison International	$ 53.21	$ 1.27	2.4%	5.0%	8.3%	8.3%	7.6%	7.4%	10.7%	10.7%	9.9%
11	Empire District Elec	$ 21.03	$ 1.28	6.1%	10.0%	6.0%	NA	3.9%	16.1%	12.1%	NA	10.0%
12	Hawaiian Elec.	$ 26.54	$ 1.24	4.7%	5.0%	10.2%	4.2%	3.3%	9.7%	14.9%	8.9%	8.0%
13	IDACORP, Inc.	$ 30.98	$ 1.20	3.9%	3.0%	6.0%	6.0%	4.2%	6.9%	9.9%	9.9%	8.1%
14	ITC Holdings Corp.	$ 54.83	$ 1.16	2.1%	NA	16.4%	17.0%	17.9%	NA	18.5%	19.1%	20.0%
15	NiSource Inc.	$ 18.17	$ 0.92	5.1%	5.0%	2.7%	3.0%	2.5%	10.1%	7.8%	8.1%	7.5%
16	Northeast Utilities	$ 26.19	$ 0.85	3.2%	13.5%	8.4%	10.0%	6.2%	16.7%	11.6%	13.2%	9.4%
17	Pepco Holdings	$ 26.51	$ 1.08	4.1%	13.0%	11.0%	9.6%	5.7%	17.1%	15.1%	13.7%	9.7%
18	PG&E Corp. (3)	$ 40.70	$ 1.59	3.9%	5.0%	7.4%	7.8%	5.5%	8.9%	11.3%	11.7%	9.4%
19	Portland General Elec.	$ 23.98	$ 1.00	4.2%	7.0%	7.1%	7.0%	3.8%	11.2%	11.3%	11.2%	8.0%
20	PPL Corp.	$ 50.05	$ 1.40	2.8%	14.0%	17.0%	16.3%	10.4%	16.8%	19.8%	19.1%	13.2%
21	Progress Energy	$ 42.51	$ 2.47	5.8%	5.0%	6.4%	4.7%	2.7%	10.8%	12.2%	10.5%	8.5%
22	P S Enterprise Group	$ 43.91	$ 1.32	3.0%	10.0%	15.9%	14.3%	8.3%	13.0%	18.9%	17.3%	11.3%
23	TECO Energy	$ 19.52	$ 0.81	4.1%	4.5%	5.6%	9.0%	5.2%	8.6%	9.7%	13.1%	9.4%
24	UIL Holdings (4)	$ 31.11	$ 1.73	5.6%	4.5%	6.0%	6.0%	2.7%	10.1%	11.6%	11.6%	8.3%
25	Westar Energy	$ 23.66	$ 1.17	4.9%	1.5%	5.5%	5.0%	3.1%	6.4%	10.4%	9.9%	8.1%
26	Wisconsin Energy	$ 48.38	$ 1.12	2.3%	9.0%	9.7%	9.6%	7.6%	11.3%	12.0%	11.9%	9.9%
27	Xcel Energy, Inc.	$ 21.46	$ 0.96	4.5%	7.5%	6.9%	5.4%	4.9%	12.0%	11.4%	9.9%	9.4%
	Average (g)								11.7%	11.6%	11.1%	9.5%

(a) Recent price and estimated dividend for next 12 mos. from The Value Line Investment Survey, *Summary and Ind*(May 30, 2008).
(b) The Value Line Investment Survey (Mar. 28, May 9, & May 30, 2008).
(c) Thompson Financial, *Company in Context Report*(June 6, 2008).
(d) http://www.zacks.com/research (retrieved June 8, 2008).
(e) See Exhibit 3.
(f) Sum of dividend yield and respective growth rate.
(g) Excludes highlighted figures.

SUSTAINABLE GROWTH

Exhibit 18
Page 1 of 1

UTILITY PROXY GROUP

		(a)	(a)	(a)	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Projections			Historical		Mid-Year					
				Net Book	Net Book	Annual	Adjustment		Adjusted	"b x r"	"sv"	Sustainable
	Company	EPS	DPS	Value	Value	Change	Factor	"b"	"r"	growth	Factor	Growth
1	Allegheny Energy	$3.20	$1.45	$26.15	$15.15	11.5%	1.0545	54.7%	12.9%	7.1%	1.00%	8.1%
2	American Elec Pwr	$4.00	$2.40	$33.75	$25.15	6.1%	1.0294	40.0%	12.2%	4.9%	0.54%	5.4%
3	Avista Corp.	$1.75	$1.20	$20.75	$17.27	3.7%	1.0184	31.4%	8.6%	2.7%	0.27%	3.0%
4	Black Hills Corp.	$3.00	$1.57	$31.75	$25.66	4.4%	1.0213	47.7%	9.7%	4.6%	0.11%	4.7%
5	CenterPoint Energy	$1.50	$0.95	$9.00	$5.61	9.9%	1.0472	36.7%	17.5%	6.4%	2.09%	8.5%
6	Cleco Corp.	$2.25	$1.50	$21.50	$16.85	5.0%	1.0244	33.3%	10.7%	3.6%	0.83%	4.4%
7	CMS Energy	$1.50	$1.00	$13.25	$9.46	7.0%	1.0337	33.3%	11.7%	3.9%	0.47%	4.4%
8	DPL, Inc.	$2.35	$1.34	$12.40	$7.69	10.0%	1.0477	43.0%	19.9%	8.5%	-0.29%	8.2%
9	DTE Energy Co.	$3.75	$2.30	$42.00	$36.08	3.1%	1.0152	38.7%	9.1%	3.5%	0.00%	3.5%
10	Edison International	$4.50	$1.64	$39.45	$25.92	8.8%	1.0420	63.6%	11.9%	7.6%	0.01%	7.6%
11	Empire District Elec	$2.00	$1.40	$18.00	$16.04	2.3%	1.0115	30.0%	11.2%	3.4%	0.54%	3.9%
12	Hawaiian Elec.	$1.75	$1.24	$16.75	$15.29	1.8%	1.0091	29.1%	10.5%	3.1%	0.27%	3.3%
13	IDACORP, Inc.	$2.35	$1.20	$29.40	$26.79	1.9%	1.0093	48.9%	8.1%	3.9%	0.29%	4.2%
14	ITC Holdings Corp.	$4.75	$2.30	$26.55	$13.12	15.1%	1.0704	51.6%	19.1%	9.9%	7.99%	17.9%
15	NiSource Inc.	$1.50	$1.00	$20.50	$18.52	2.1%	1.0102	33.3%	7.4%	2.5%	0.01%	2.5%
16	Northeast Utilities	$2.40	$1.03	$25.80	$18.65	6.7%	1.0324	57.1%	9.6%	5.5%	0.69%	6.2%
17	Pepco Holdings	$3.10	$1.80	$24.20	$20.04	3.8%	1.0189	41.9%	13.1%	5.5%	0.19%	5.7%
18	PG&E Corp.	$3.50	$2.04	$28.95	$22.60	5.1%	1.0248	41.7%	12.4%	5.2%	0.36%	5.5%
19	Portland General Elec.	$2.25	$1.35	$25.50	$21.05	3.9%	1.0192	40.0%	9.0%	3.6%	0.25%	3.8%
20	PPL Corp.	$5.00	$2.40	$23.75	$14.88	9.8%	1.0467	52.0%	22.0%	11.5%	-1.06%	10.4%
21	Progress Energy	$3.40	$2.55	$35.75	$32.38	2.0%	1.0099	25.0%	9.6%	2.4%	0.28%	2.7%
22	P S Enterprise Group	$3.45	$1.65	$23.75	$14.35	10.6%	1.0503	52.2%	15.3%	8.0%	0.33%	8.3%
23	TECO Energy	$1.50	$0.90	$12.00	$9.56	4.7%	1.0227	40.0%	12.8%	5.1%	0.12%	5.2%
24	UIL Holdings	$2.20	$1.73	$21.05	$18.55	2.6%	1.0126	21.4%	10.6%	2.3%	0.49%	2.7%
25	Westar Energy	$1.95	$1.32	$21.80	$19.14	2.6%	1.0130	32.3%	9.1%	2.9%	0.21%	3.1%
26	Wisconsin Energy	$4.25	$1.60	$36.00	$26.50	6.3%	1.0306	62.4%	12.2%	7.6%	0.00%	7.6%
27	Xcel Energy, Inc.	$2.00	$1.15	$18.25	$14.70	4.4%	1.0216	42.5%	11.2%	4.8%	0.16%	4.9%

(a) The Value Line Investment Survey (Mar. 28, May 9, & May 30, 2008).
(b) Annual growth in book value per share from historical to projected period.
(c) Equal to 2(1+b)/(2+b), where b = annual change in net book value.
(d) (EPS-DPS)/EPS.
(e) (Projected EPS/Projected Net Book Value) x Mid-Year Adjustment Factor.
(f) (d) x (e).
(g) "s" equals projected market-to-book ratio x growth in common shares. "v" equals (1- 1/projected market-to-book ratio).
(h) (f) + (g).

CONSTANT GROWTH DCF MODEL

NON-UTILITY PROXY GROUP

		(a)	(a)	(b)	(d)	(e)	(f)	(f)	(f)	(f)
		Dividend	Earnings Growth Rates				Cost of Equity Estimates			
	Company	Yield	V Line	IBES	Zacks	br+sv	V Line	IBES	Zacks	br+sv
1	3M Company	2.57%	4.0%	11.3%	10.7%	12.0%	$\boxed{6.6\%}$	13.9%	13.3%	14.5%
2	Abbott Labs.	2.57%	11.5%	11.3%	10.5%	13.5%	14.1%	13.9%	13.1%	16.1%
3	Aflac Inc.	1.42%	14.5%	14.8%	14.5%	10.9%	15.9%	16.2%	15.9%	12.3%
4	Allergan, Inc.	0.36%	14.5%	18.0%	18.0%	15.0%	14.9%	$\boxed{18.4\%}$	$\boxed{18.4\%}$	15.3%
5	Allstate Corp.	3.20%	9.0%	7.0%	8.0%	10.6%	12.2%	10.2%	11.2%	13.8%
6	Anheuser-Busch	2.33%	6.5%	8.6%	8.8%	27.9%	8.8%	10.9%	11.1%	$\boxed{30.3\%}$
7	AT&T Inc.	3.98%	13.0%	9.7%	7.9%	4.6%	$\boxed{17.0\%}$	13.7%	11.9%	8.5%
8	Automatic Data Proc.	2.70%	10.0%	14.0%	13.3%	11.4%	12.7%	16.7%	16.0%	14.1%
9	Bard (C.R.)	0.65%	13.5%	14.5%	14.0%	13.2%	14.2%	15.2%	14.7%	13.9%
10	Baxter Int'l Inc.	1.43%	15.5%	12.7%	11.8%	15.1%	16.9%	14.1%	13.2%	16.5%
11	Becton, Dickinson	1.33%	13.0%	13.0%	14.0%	14.5%	14.3%	14.3%	15.3%	15.8%
12	Brown-Forman 'B'	1.81%	9.0%	10.2%	NA	11.1%	10.8%	12.0%	NA	12.9%
13	Coca-Cola	2.63%	8.5%	10.0%	8.7%	11.4%	11.1%	12.6%	11.3%	14.0%
14	Colgate-Palmolive	2.18%	12.0%	11.6%	11.0%	19.1%	14.2%	13.8%	13.2%	$\boxed{21.3\%}$
15	Commerce Bancshs.	2.28%	4.5%	6.5%	6.5%	7.8%	$\boxed{6.8\%}$	8.8%	8.8%	10.1%
16	Fortune Brands	2.42%	4.5%	9.1%	10.2%	10.0%	$\boxed{6.9\%}$	11.5%	12.6%	12.4%
17	Gallagher (Arthur J.)	5.05%	6.5%	8.5%	9.5%	7.8%	11.6%	13.6%	14.6%	12.9%
18	Gannett Co.	5.46%	3.5%	3.0%	7.5%	6.7%	9.0%	8.5%	13.0%	12.1%
19	Gen'l Dynamics	1.52%	11.0%	7.5%	7.0%	11.7%	12.5%	9.0%	8.5%	13.2%
20	Gen'l Electric	4.05%	10.5%	11.0%	10.4%	11.7%	14.6%	15.1%	14.5%	15.8%
21	Gen'l Mills	2.53%	8.5%	8.7%	8.8%	8.4%	11.0%	11.2%	11.3%	10.9%
22	Genuine Parts	3.53%	8.0%	9.3%	8.6%	8.3%	11.5%	12.8%	12.1%	11.8%
23	Heinz (H.J.)	3.09%	9.0%	8.8%	9.0%	13.6%	12.1%	11.9%	12.1%	16.7%
24	Hormel Foods	1.93%	11.0%	8.6%	8.4%	11.3%	12.9%	10.5%	10.3%	13.2%
25	Int'l Business Mach.	1.54%	14.5%	11.0%	10.2%	9.7%	16.0%	12.5%	11.7%	11.2%
26	Johnson & Johnson	2.77%	8.0%	8.2%	9.0%	10.3%	10.8%	11.0%	11.8%	13.0%
27	Kimberly-Clark	3.61%	7.0%	8.3%	8.3%	12.4%	10.6%	11.9%	11.9%	16.0%
28	Kraft Foods	3.29%	6.5%	7.0%	7.4%	4.8%	9.8%	10.3%	10.7%	8.1%
29	Lancaster Colony	3.41%	5.5%	NA	NA	5.9%	8.9%	NA	NA	9.3%
30	Lilly (Eli)	3.87%	7.0%	5.9%	6.3%	7.8%	10.9%	9.8%	10.2%	11.6%
31	Lockheed Martin	1.55%	12.5%	11.9%	7.9%	15.1%	14.1%	13.5%	9.5%	16.6%
32	McDonald's Corp.	2.52%	11.5%	10.9%	12.1%	4.3%	14.0%	13.4%	14.6%	$\boxed{6.8\%}$
33	Medtronic, Inc.	0.99%	12.0%	13.8%	13.7%	11.8%	13.0%	14.8%	14.7%	12.8%
34	Meredith Corp.	2.60%	13.0%	11.5%	14.5%	10.4%	15.6%	14.1%	$\boxed{17.1\%}$	13.0%

CONSTANT GROWTH DCF MODEL

NON-UTILITY PROXY GROUP

		(a)	(a)	(b)	(d)	(e)	(f)	(f)	(f)	(f)
		Dividend	Earnings Growth Rates				Cost of Equity Estimates			
	Company	Yield	V Line	IBES	Zacks	br+sv	V Line	IBES	Zacks	br+sv
35	Microsoft Corp.	1.55%	17.0%	11.4%	12.3%	-2.2%	18.6%	13.0%	13.9%	-0.6%
36	NIKE, Inc. 'B'	1.35%	11.5%	14.1%	13.9%	10.7%	12.9%	15.5%	15.3%	12.0%
37	Northrop Grumman	2.14%	11.5%	15.0%	8.3%	8.1%	13.6%	17.1%	10.4%	10.2%
38	PepsiCo, Inc.	2.47%	10.5%	10.9%	10.8%	11.0%	13.0%	13.4%	13.3%	13.4%
39	Pfizer, Inc.	6.60%	1.5%	4.3%	5.2%	3.7%	8.1%	10.9%	11.8%	10.3%
40	Procter & Gamble	2.44%	9.5%	11.9%	11.6%	6.4%	11.9%	14.3%	14.0%	8.8%
41	Raytheon Co.	1.77%	13.0%	14.0%	9.0%	8.2%	14.8%	15.8%	10.8%	10.0%
42	Reinsurance Group	0.70%	12.0%	11.0%	11.5%	11.7%	12.7%	11.7%	12.2%	12.4%
43	Sigma-Aldrich	0.89%	10.0%	9.8%	10.5%	14.0%	10.9%	10.7%	11.4%	14.8%

CONSTANT GROWTH DCF MODEL

NON-UTILITY PROXY GROUP

		(a)	(a)	(b)	(d)	(e)	(f)	(f)	(f)	(f)
		Dividend	Earnings Growth Rates				Cost of Equity Estimates			
	Company	Yield	V Line	IBES	Zacks	br+sv	V Line	IBES	Zacks	br+sv
44	Sysco Corp.	2.84%	12.0%	13.3%	12.3%	12.1%	14.8%	16.1%	15.1%	14.9%
45	Tootsie Roll Ind.	1.25%	3.0%	NA	NA	5.5%	4.3%	NA	NA	6.7%
46	Torchmark Corp.	0.88%	8.0%	9.2%	NA	10.3%	8.9%	10.1%	NA	11.2%
47	United Parcel Serv.	2.51%	7.5%	11.8%	11.6%	15.1%	10.0%	14.3%	14.1%	17.6%
48	Verizon Communic.	4.48%	3.5%	8.7%	7.2%	8.9%	8.0%	13.2%	11.7%	13.4%
49	Wal-Mart Stores	1.64%	10.0%	11.7%	11.3%	10.7%	11.6%	13.3%	12.9%	12.4%
50	Walgreen Co.	1.06%	13.0%	14.0%	14.7%	13.1%	14.1%	15.1%	15.8%	14.2%
51	Washington Federal	3.78%	10.5%	8.0%	6.0%	10.2%	14.3%	11.8%	9.8%	14.0%
52	Washington Post	1.35%	3.5%	10.0%	NA	6.3%	4.9%	11.4%	NA	7.6%
53	Weis Markets	3.28%	5.0%	NA	NA	4.8%	8.3%	NA	NA	8.1%
54	Wrigley (Wm.) Jr.	1.74%	9.5%	10.5%	10.0%	10.4%	11.2%	12.2%	11.7%	12.1%
	Average (g)						12.3%	12.8%	12.5%	12.7%

(a) www.valueline.com (retrieved June 4, 2008).
(b) Thompson Financial, *Company in Context Report* (June 4, 2008).
(c) http://stocks.us.reuters.com (retrieved Apr. 17, 2008).
(d) http://www.zacks.com/research (retrieved June 5, 2008).
(e) See Schedule WEA-7.
(f) Sum of dividend yield and respective growth rate.
(g) Excludes highlighted figures.

SUSTAINABLE GROWTH

NON-UTILITY PROXY GROUP

		(a)	(a)	(a)	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Projections			Historical		Mid-Year					
				Net Book	Net Book	Annual	Adjustment		Adjusted	"b x r"	"sv"	Sustainable
	Company	EPS	DPS	Value	Value	Change	Factor	"b"	"r"	growth	Factor	Growth
1	3M Company	$6.25	$2.28	$28.15	$16.56	11.2%	1.0530	63.5%	23.4%	14.9%	-2.88%	12.0%
2	Abbott Labs.	$5.05	$2.10	$21.45	$11.47	13.3%	1.0625	58.4%	25.0%	14.6%	-1.11%	13.5%
3	Aflac Inc.	$6.50	$1.88	$30.70	$18.08	11.2%	1.0529	71.1%	22.3%	15.8%	-4.98%	10.9%
4	Allergan, Inc.	$3.85	$0.30	$28.55	$12.22	18.5%	1.0847	92.2%	14.6%	13.5%	1.47%	15.0%
5	Allstate Corp.	$8.75	$2.25	$61.90	$38.81	9.8%	1.0467	74.3%	14.8%	11.0%	-0.35%	10.6%
6	Anheuser-Busch	$4.05	$1.46	$8.20	$4.22	14.2%	1.0663	64.0%	52.7%	33.7%	-5.76%	27.9%
7	AT&T Inc.	$4.70	$2.60	$26.90	$19.09	7.1%	1.0343	44.7%	18.1%	8.1%	-3.51%	4.6%
8	Automatic Data Proc.	$3.25	$1.35	$20.30	$9.61	16.1%	1.0746	58.5%	17.2%	10.1%	1.35%	11.4%
9	Bard (C.R.)	$7.15	$0.95	$31.55	$18.44	11.3%	1.0537	86.7%	23.9%	20.7%	-7.46%	13.2%
10	Baxter Int'l Inc.	$5.25	$1.25	$24.50	$10.91	17.6%	1.0807	76.2%	23.2%	17.6%	-2.57%	15.1%
11	Becton, Dickinson	$6.85	$1.90	$35.00	$17.89	14.4%	1.0670	72.3%	20.9%	15.1%	-0.64%	14.5%
12	Brown-Forman 'B'	$5.20	$1.78	$26.75	$14.15	13.6%	1.0636	65.8%	20.7%	13.6%	-2.48%	11.1%
13	Coca-Cola	$3.90	$1.84	$17.00	$9.38	12.6%	1.0594	52.8%	24.3%	12.8%	-1.44%	11.4%
14	Colgate-Palmolive	$5.80	$2.30	$13.55	$4.10	27.0%	1.1190	60.3%	47.9%	28.9%	-9.82%	19.1%
15	Commerce Bancshs.	$3.70	$1.20	$32.15	$21.25	8.6%	1.0414	67.6%	12.0%	8.1%	-0.30%	7.8%
16	Fortune Brands	$6.85	$1.76	$51.30	$36.94	6.8%	1.0328	74.3%	13.8%	10.2%	-0.26%	10.0%
17	Gallagher (Arthur J.)	$2.25	$1.44	$10.65	$7.78	6.5%	1.0314	36.0%	21.8%	7.8%	0.00%	7.8%
18	Gannett Co.	$5.65	$2.08	$53.50	$39.17	6.4%	1.0312	63.2%	10.9%	6.9%	-0.23%	6.7%
19	Gen'l Dynamics	$8.00	$1.70	$51.15	$29.13	11.9%	1.0562	78.8%	16.5%	13.0%	-1.29%	11.7%
20	Gen'l Electric	$3.60	$1.45	$18.95	$11.57	10.4%	1.0493	59.7%	19.9%	11.9%	-0.19%	11.7%
21	Gen'l Mills	$4.85	$2.10	$21.75	$15.64	6.8%	1.0330	56.7%	23.0%	13.1%	-4.67%	8.4%
22	Genuine Parts	$4.35	$1.95	$25.65	$16.36	9.4%	1.0449	55.2%	17.7%	9.8%	-1.52%	8.3%
23	Heinz (H.J.)	$4.25	$2.00	$12.20	$5.85	15.8%	1.0734	52.9%	37.4%	19.8%	-6.18%	13.6%
24	Hormel Foods	$3.75	$1.20	$23.35	$13.89	10.9%	1.0519	68.0%	16.9%	11.5%	-0.19%	11.3%
25	Int'l Business Mach.	$13.75	$2.15	$30.25	$20.55	8.0%	1.0386	84.4%	47.2%	39.8%	-30.13%	9.7%
26	Johnson & Johnson	$6.00	$2.40	$26.00	$15.25	11.3%	1.0533	60.0%	24.3%	14.6%	-4.32%	10.3%
27	Kimberly-Clark	$6.00	$2.95	$19.00	$12.41	8.9%	1.0426	50.8%	32.9%	16.7%	-4.32%	12.4%
28	Kraft Foods	$2.75	$1.40	$26.20	$17.80	8.0%	1.0386	49.1%	10.9%	5.4%	-0.53%	4.8%
29	Lancaster Colony	$3.00	$1.35	$23.20	$14.45	9.9%	1.0473	55.0%	13.5%	7.4%	-1.54%	5.9%

SUSTAINABLE GROWTH

NON-UTILITY PROXY GROUP

		(a)	(a)	(a)	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Projections			Historical		Mid-Year					
				Net Book	Net Book	Annual	Adjustment		Adjusted	"b x r"	"sv"	Sustainable
	Company	EPS	DPS	Value	Value	Change	Factor	"b"	"r"	growth	Factor	Growth
30	Lilly (Eli)	$4.15	$2.16	$20.45	$12.05	11.2%	1.0528	48.0%	21.4%	10.2%	-2.48%	7.8%
31	Lockheed Martin	$11.00	$2.50	$37.65	$23.97	9.5%	1.0451	77.3%	30.5%	23.6%	-8.52%	15.1%
32	McDonald's Corp.	$4.65	$2.60	$17.80	$13.11	6.3%	1.0306	44.1%	26.9%	11.9%	-7.54%	4.3%
33	Medtronic, Inc.	$4.80	$0.89	$20.10	$10.30	14.3%	1.0668	81.5%	25.5%	20.8%	-8.91%	11.8%
34	Meredith Corp.	$4.80	$0.90	$29.45	$17.27	11.3%	1.0533	81.3%	17.2%	13.9%	-3.53%	10.4%
35	Microsoft Corp.	$3.25	$0.90	$10.15	$3.32	25.0%	1.1113	72.3%	35.6%	25.7%	-27.92%	-2.2%
36	NIKE, Inc. 'B'	$5.00	$1.50	$22.95	$13.94	10.5%	1.0498	70.0%	22.9%	16.0%	-5.34%	10.7%
37	Northrop Grumman	$8.35	$2.10	$72.50	$52.35	6.7%	1.0326	74.9%	11.9%	8.9%	-0.82%	8.1%
38	PepsiCo, Inc.	$5.80	$2.12	$16.45	$10.71	9.0%	1.0429	63.4%	36.8%	23.3%	-12.35%	11.0%
39	Pfizer, Inc.	$2.30	$1.40	$11.40	$9.60	3.5%	1.0172	39.1%	20.5%	8.0%	-4.37%	3.7%
40	Procter & Gamble	$4.75	$1.95	$32.30	$20.87	9.1%	1.0436	58.9%	15.3%	9.0%	-2.68%	6.4%
41	Raytheon Co.	$5.50	$1.75	$40.50	$29.43	6.6%	1.0319	68.2%	14.0%	9.6%	-1.31%	8.2%
42	Reinsurance Group	$9.00	$0.50	$75.35	$51.42	7.9%	1.0382	94.4%	12.4%	11.7%	-0.06%	11.7%
43	Sigma-Aldrich	$3.60	$0.70	$17.65	$12.24	7.6%	1.0366	80.6%	21.1%	17.0%	-3.07%	14.0%
44	Sysco Corp.	$2.90	$1.25	$9.20	$5.36	11.4%	1.0540	56.9%	33.2%	18.9%	-6.82%	12.1%
45	Tootsie Roll Ind.	$1.25	$0.38	$16.70	$12.13	6.6%	1.0320	69.6%	7.7%	5.4%	0.09%	5.5%
46	Torchmark Corp.	$8.00	$0.75	$62.35	$36.07	11.6%	1.0547	90.6%	13.5%	12.3%	-1.95%	10.3%
47	United Parcel Serv.	$5.80	$2.20	$19.50	$11.78	10.6%	1.0504	62.1%	31.2%	19.4%	-4.28%	15.1%
48	Verizon Communic.	$3.50	$1.72	$18.75	$17.50	1.4%	1.0069	50.9%	18.8%	9.6%	-0.61%	8.9%
49	Wal-Mart Stores	$5.15	$1.35	$23.50	$16.26	7.6%	1.0368	73.8%	22.7%	16.8%	-6.02%	10.7%
50	Walgreen Co.	$3.45	$0.54	$22.30	$11.20	14.8%	1.0688	84.3%	16.5%	13.9%	-0.81%	13.1%
51	Washington Federal	$2.90	$1.04	$19.10	$15.07	4.9%	1.0237	64.1%	15.5%	10.0%	0.20%	10.2%
52	Washington Post	$40.40	$10.20	$495.30	$362.48	6.4%	1.0312	74.8%	8.4%	6.3%	-0.04%	6.3%
53	Weis Markets	$2.70	$1.35	$28.60	$24.04	3.5%	1.0174	50.0%	9.6%	4.8%	0.01%	4.8%
54	Wrigley (Wm.) Jr.	$3.55	$1.64	$16.95	$10.28	10.5%	1.0500	53.8%	22.0%	11.8%	-1.43%	10.4%

(a) www.valueline.com (retrieved June 4, 2008).
(b) Annual growth in book value per share from historical to projected period.
(c) Equal to 2(1+b)/(2+b), where b = annual change in net book value.
(d) (EPS-DPS)/EPS.
(e) (Projected EPS/Projected Net Book Value) x Mid-Year Adjustment Factor.
(f) [illegible] (e).

SUSTAINABLE GROWTH

NON-UTILITY PROXY GROUP

	(a)	(a)	(a)	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Projections			Historical		Mid-Year					
			Net Book	Net Book	Annual	Adjustment		Adjusted	"b x r"	"sv"	Sustainable
Company	EPS	DPS	Value	Value	Change	Factor	"b"	"r"	growth	Factor	Growth

(g) "s" equals projected market-to-book ratio x growth in common shares. "v" equals (1- 1/projected market-to-book ratio).
(h) (f) + (g).

FORWARD-LOOKING CAPM

Exhibit 21
Page 1 of 1

UTILITY PROXY GROUP

Market Rate of Return		
Dividend Yield (a)	2.4%	
Growth Rate (b)	10.6%	
Market Return (c)		12.9%
Less: Risk-Free Rate (d)		
Long-term Treasury Bond Yield		4.6%
Market Risk Premium (e)		8.3%
Proxy Group Beta (f)		0.88
Proxy Group Risk Premium (g)		7.3%
Plus: Risk-free Rate (d)		
Long-term Treasury Bond Yield		4.6%
Implied Cost of Equity (h)		**11.9%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived June 6, 2008).
(b) Weighted average of IBES, Zacks, and Value Line growth rates for the dividend paying firms in the S&P 500 based on data from Thomson Financial *Company in Context Report* (June 10, 2008), www.zacks.com (retrieved June 11, 2008), and www.valueline.com (retrieved June 6, 2008).
(c) (a) + (b)
(d) Average yield on 20-year Treasury bonds for May 2008 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/Monthly/H15_TCMNOM_Y20.txt.
(e) (c) - (d).
(f) The Value Line Investment Survey (Mar. 28, May 9, & May 30, 2008).
(g) (e) x (f).
(h) (d) + (g).

FORWARD-LOOKING CAPM

Exhibit 22
Page 1 of 1

NON-UTILITY PROXY GROUP

Market Rate of Return		
Dividend Yield (a)	2.4%	
Growth Rate (b)	10.6%	
Market Return (c)		12.9%
Less: Risk-Free Rate (d)		
Long-term Treasury Bond Yield		4.6%
Market Risk Premium (e)		8.3%
Proxy Group Beta (f)		0.79
Proxy Group Risk Premium (g)		6.6%
Plus: Risk-free Rate (d)		
Long-term Treasury Bond Yield		4.6%
Implied Cost of Equity (h)		11.2%

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived June 6, 2008).
(b) Weighted average of IBES, Zacks, and Value Line growth rates for the dividend paying firms in the S&P 500 based on data from Thomson Financial *Company in Context Report* (June 10, 2008), www.zacks.com (retrieved June 11, 2008), and www.valueline.com (retrieved June 6, 2008).
(c) (a) + (b)
(d) Average yield on 20-year Treasury bonds for May 2008 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/Monthly/H15_TCMNOM_ Y20.txt.
(e) (c) - (d).
(f) www.valueline.com (retrieved June 4, 2008).
(g) (e) x (f).
(h) (d) + (g).

HISTORICAL CAPM **Exhibit 23**

Page 1 of 1

UTILITY PROXY GROUP

Market Risk Premium	
Long-Horizon Equity Risk Premium (a)	7.1%
Proxy Group Beta (b)	0.88
Proxy Group Risk Premium (c)	6.2%
Plus: Risk-free Rate (d)	
Long-term Treasury Bond Yield	4.6%
Implied Cost of Equity (e)	10.8%

(a) Arithmetic mean risk premium on Large Company Stocks from 1926-2007 reported by Ibbotson Associates, *Stocks, Bonds, Bills, and Inflation, Valuation Edition, 2008 Yearbook*, at Appendix C, Table C-1, p. 262.
(b) The Value Line Investment Survey (Mar. 28, May 9, & May 30, 2008).
(c) (a) x (b).
(d) Average yield on 20-year Treasury bonds for May 2008 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/Monthly/H15_TCMNOM_ Y20.txt.
(e) (c) + (d).

HISTORICAL CAPM **Exhibit 24**

Page 1 of 1

NON-UTILITY PROXY GROUP

Market Risk Premium	
Long-Horizon Equity Risk Premium (a)	7.1%
Proxy Group Beta (b)	0.79
Proxy Group Risk Premium (c)	5.6%
Plus: Risk-free Rate (d)	
Long-term Treasury Bond Yield	4.6%
Implied Cost of Equity (e)	10.2%

(a) Arithmetic mean risk premium on Large Company Stocks from 1926-2007 reported by Ibbotson Associates, *Stocks, Bonds, Bills, and Inflation, Valuation Edition, 2008 Yearbook*, at Appendix C, Table C-1, p. 262.
(b) www.valueline.com (retrieved June 4, 2008).
(c) (a) x (b).
(d) Average yield on 20-year Treasury bonds for May 2008 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/Monthly/H15_TCMNOM_Y20.txt.
(e) (c) + (d).

EXPECTED EARNINGS APPROACH

Exhibit 25
Page 1 of 1

UTILITY PROXY GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	Allegheny Energy	12.0%	1.0545	12.7%
2	American Elec Pwr	12.0%	1.0294	12.4%
3	Avista Corp.	8.5%	1.0184	8.7%
4	Black Hills Corp.	9.5%	1.0213	9.7%
5	CenterPoint Energy	17.0%	1.0472	17.8%
6	Cleco Corp.	11.0%	1.0244	11.3%
7	CMS Energy	12.0%	1.0337	12.4%
8	DPL, Inc.	19.0%	1.0477	19.9%
9	DTE Energy Co.	9.0%	1.0152	9.1%
10	Edison International	11.5%	1.0420	12.0%
11	Empire District Elec	11.0%	1.0115	11.1%
12	Hawaiian Elec.	10.5%	1.0091	10.6%
13	IDACORP, Inc.	7.5%	1.0093	7.6%
14	ITC Holdings Corp.	18.0%	1.0704	19.3%
15	NiSource Inc.	7.5%	1.0102	7.6%
16	Northeast Utilities	9.5%	1.0324	9.8%
17	Pepco Holdings	11.0%	1.0189	11.2%
18	PG&E Corp. (3)	11.5%	1.0248	11.8%
19	Portland General Elec.	9.0%	1.0192	9.2%
20	PPL Corp.	22.0%	1.0467	23.0%
21	Progress Energy	9.5%	1.0099	9.6%
22	P S Enterprise Group	14.5%	1.0503	15.2%
23	TECO Energy	12.5%	1.0227	12.8%
24	UIL Holdings (4)	10.5%	1.0126	10.6%
25	Westar Energy	9.0%	1.0130	9.1%
26	Wisconsin Energy	12.0%	1.0306	12.4%
27	Xcel Energy, Inc.	11.0%	1.0216	11.2%
	Average (d)			11.1%

(a) 3-5 year projections from The Value Line Investment Survey (Mar. 28, May 9, & May 30, 2008).
(b) Adjustment to convert year-end "r" to an average rate of return from Exhibit 3.
(c) (a) × (b).
(d). Excludes highlighted figures.

CAPITAL STRUCTURE

Exhibit 26
Page 1 of 1

UTILITY PROXY GROUP

		At Fiscal Year-End 2007 (a)			Value Line Projected (b)		
	Company	Long-term Debt	Preferred	Common Equity	Long-term Debt	Other	Common Equity
1	Allegheny Energy	61.3%	0.0%	38.7%	52.0%	0.0%	48.0%
2	American Elec Pwr	59.7%	0.2%	40.1%	59.0%	0.5%	40.5%
3	Avista Corp.	48.0%	5.7%	46.2%	47.5%	0.0%	52.5%
4	Black Hills Corp.	42.1%	0.0%	57.9%	40.5%	0.0%	59.5%
5	CenterPoint Energy	86.2%	0.0%	13.8%	69.5%	0.0%	30.5%
6	Cleco Corp.	46.2%	0.1%	53.7%	46.0%	0.0%	54.0%
7	CMS Energy	71.7%	3.4%	24.9%	68.0%	3.0%	29.0%
8	DPL, Inc.	64.7%	0.9%	34.4%	53.0%	1.0%	46.0%
9	DTE Energy Co.	53.5%	2.2%	44.3%	55.0%	0.0%	45.0%
10	Edison International	48.3%	4.9%	46.8%	48.5%	3.5%	48.0%
11	Empire District Elec	50.1%	0.0%	49.9%	44.5%	0.0%	55.5%
12	Hawaiian Elec.	48.7%	1.3%	50.0%	45.5%	1.5%	53.0%
13	IDACORP, Inc.	50.6%	0.0%	49.4%	50.0%	0.0%	50.0%
14	ITC Holdings Corp.	79.9%	0.0%	20.1%	64.5%	0.0%	35.5%
15	NiSource Inc.	52.6%	0.0%	47.4%	53.0%	0.0%	47.0%
16	Northeast Utilities	54.6%	1.7%	43.7%	51.5%	1.5%	47.0%
17	Pepco Holdings	52.8%	0.0%	47.2%	53.0%	0.0%	47.0%
18	PG&E Corp. (3)	48.1%	1.5%	50.4%	48.0%	1.0%	51.0%
19	Portland General Elec.	49.9%	0.0%	50.1%	50.0%	0.0%	50.0%
20	PPL Corp.	56.3%	2.2%	41.5%	43.5%	1.5%	55.0%
21	Progress Energy	52.8%	0.5%	46.7%	49.5%	0.5%	50.0%
22	P S Enterprise Group	52.8%	0.5%	46.7%	49.5%	0.5%	50.0%
23	TECO Energy	61.1%	0.0%	38.9%	58.0%	0.0%	42.0%
24	UIL Holdings (4)	55.7%	0.0%	44.3%	49.0%	0.0%	51.0%
25	Westar Energy	50.6%	0.6%	48.9%	51.5%	0.5%	48.0%
26	Wisconsin Energy	53.0%	0.5%	46.6%	48.5%	0.5%	51.0%
27	Xcel Energy, Inc.	52.1%	0.8%	47.1%	51.5%	0.5%	48.0%
	Average	55.7%	1.0%	43.3%	51.9%	0.6%	47.6%

(a) Company Form 10-K and Annual Reports.
(b) The Value Line Investment Survey (Mar. 28, May 9, & May 30, 2008).

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE _______

IN THE MATTER OF THE APPLICATION)
OF IDAHO POWER COMPANY FOR)
AUTHORITY TO INCREASE ITS RATES)
AND CHARGES FOR ELECTRIC)
SERVICE IN THE STATE OF OREGON.)
_________________________________)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

STEVEN R. KEEN

July 31, 2009

Q. Please state your name, address, and present occupation.

A. My name is Steven R. Keen and my business address is 1221 West Idaho Street, Boise, Idaho. I am employed by Idaho Power Company ("Idaho Power" or "Company") as Vice President and Treasurer.

Q. What is your educational background?

A. I graduated with high honors in 1981 from Idaho State University, Pocatello, Idaho, receiving a Bachelor of Business Administration degree in Accounting. I have also attended numerous seminars and conferences on accounting and finance issues related to the utility industry. I am a Certified Public Accountant licensed in the state of Idaho.

Q. Please describe your business experience with Idaho Power Company.

A. I joined Idaho Power in September 1982 in the Property Accounting Department. In March 1983, I transferred to the Tax Department as a Tax Accountant. From that time through December 1998, I advanced through every position in the Tax Department, including Property Tax Representative, Tax Research Coordinator, and, finally, Corporate Tax Director. In January 1999, I became President of IDACORP Financial Services. In June of 2006, I accepted the position of Vice President and Treasurer of Idaho Power Company and IDACORP, Inc.

In the course of my duties with Idaho Power Company, I presented testimony in Idaho Power's last two general rate cases before the Idaho Public Utilities Commission ("IPUC" or "Idaho Commission"), Case No. IPC-E-07-08 and Case No. IPC-E-08-10. I have also presented tax testimony to the Internal Revenue Service as well as tax and/or capitalization rate testimony to the Departments of Revenue and Taxation for Idaho, Oregon, Wyoming, and Nevada.

Q. What are your duties as Vice President and Treasurer of Idaho Power as they relate to this proceeding?

A. I oversee the direct financial planning, procurement, and investment of funds for Idaho Power, as well as supervise corporate liquidity management.

My duties and responsibilities include various aspects of all the Company's financings and other financial matters. With respect to long-term financings, sale of bonds and equity, my duties include development of financial plans with senior officers, meeting with representatives of investment banking firms that are interested in underwriting Idaho Power securities, discussions with credit rating agencies, assisting in preparation of financial material (including Registration Statements filed with the Securities and Exchange Commission), representing the Company at informational meetings for investment banking firms, reviewing information relative to the Company's financings, and recommending disposition of net proceeds. With respect to short-term financings, these duties and responsibilities include negotiation of lines of credit with commercial banks and overseeing the sale of commercial paper.

Q. Do your responsibilities include communicating with members of the financial community?

A. Yes. I am in continuous contact with individuals representing investment and commercial banking firms, credit rating agencies, insurance companies, institutional investment firms, and other organizations interested in publicly traded securities, all of whom actively follow IDACORP and Idaho Power. Along with the Company's Chief Financial Officer and the Director of Investor Relations, my responsibilities include keeping these representatives of the financial community informed of the Company's financial condition, arranging meetings with these people and Idaho Power's senior executive management, and visiting with financial representatives in their respective offices. Some of these members of the investment community have followed the electric utility industry for an extended period of time and have a great deal of expertise in the financial problems and prospects of utilities.

Through my continuous contact with the financial community and review of investment banking analytical reports and articles issued by these firms and the rating agencies, I am able to keep informed on trends, interest rates, financing costs, security ratings, and other financial developments in the public utility industry.

Q. Are you a member of any professional societies or associations?

A. Yes. I am a current member and past board president of the Idaho Society of Certified Public Accountants. I am a current member of and past council member of the American Institute of Certified Public Accountants. I am a current member and past board chairman of the Associated Taxpayers of Idaho. I am the current board chairman of the Idaho Tax Foundation. I am a member of the Idaho Association for Financial Professionals. Also, in 2008, I was appointed by Idaho Governor Otter to the Board of Commissioners for the Idaho Housing and Finance Association.

In addition to the above activities, I attend numerous conferences and seminars of these and other utility professional groups such as the Edison Electric Institute. Through participation in these events, I gain additional information and insights into the financial developments affecting Idaho Power as well as the electric utility industry.

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

A. I am sponsoring testimony as to the point estimate for Idaho Power's rate of return on common equity and the embedded cost of long-term debt, risk factors generally, risk factors that are unique to Idaho Power, the use of a forecasted year-end 2009 capital structure, and the resultant overall cost of capital used to compute the Company's revenue requirement.

Q. What exhibits are you sponsoring?

A. I am sponsoring Exhibit Nos. 301-304.

COST OF EQUITY POINT ESTIMATE

Q. What return on equity are you recommending in this proceeding?

A. I recommend 11.25 percent as the point estimate for cost of equity for the Company.

Q. Does that point estimate align with the recommendations made by the Company's cost of capital witness Mr. Avera?

A. It does. Mr. Avera performed a complete analysis of the Company for the 2008 year as part of the Idaho general rate case, Case No. IPC-E-08-10, and recommended a range for cost of capital of 10.8 to 11.8 percent, excluding the effects of flotation. Mr. Avera has updated his analysis and provided updated testimony in this case in which he indicates that my recommended 11.25 percent ROE is still reasonable based on 2009 data and that if any change were made to the recommended cost of equity, it would be an upward change. The 11.25 percent is consistent with my recommendation in the Idaho general rate case.

RISK FACTORS

Q. Could you briefly outline the risks confronting the Company that form the basis for your recommendation of an 11.25 percent return on common equity?

A. Yes. I will summarize them here and discuss them in greater detail later in my testimony. I believe that, at a minimum, an 11.25 percent return on equity is required to properly account for the risks confronting Idaho Power, namely: (1) the general decline in credit quality of the Company and its impact on meeting capital funding requirements; and (2) the inability of the Company to earn an actual return on capital that is anywhere near a reasonable allowed rate of return; (3) the variability associated with hydroelectric generating base subject to the uncertainties of weather and water; (4) the effects of pricing changes in a volatile wholesale power supply market in the Western United States and specifically their impact on the Company's perceived risk in the financial community; (5) the renewal of federal licenses for the Company's hydroelectric projects, primarily the Hells Canyon Complex, which provides 40 percent of the Company's total generating capacity, and particularly the significant cost of relicensing that project; (6) the impact of Qualified Facility ("QF") related expenditures; (7) the inability of the Company to recover the significant capital investment required for present and growing electrical requirements and service reliability for its customers on a timely basis.

Q. Are some of these risk conditions the same risk conditions that have been raised in past Idaho Power rate proceedings?

A. Yes. These risks still exist and the passage of time has exacerbated their potential impact on the Company.

Q. Are there other risks, less specific to Idaho Power, that also impact your recommendation?

A. Yes. There are general financial risks such as increased volatility in the financial markets and what I view as a heightened sensitivity to risk exposure that has evolved since the U.S. housing market began experiencing problems in 2007 and which was magnified by the very significant disruption in the financial markets that occurred in 2008. There are also industry specific risks, such as unknown costs relative to carbon emissions, an industry-wide need for infrastructure improvements, and increased capital investment as well as inflationary pressures that increase costs of both operating expenses and capital outlays. All of these factors combine to make a challenging environment in which the Company must compete with others in the electric utility industry, for both resources and capital, to serve the needs of its customers and shareowners. While I do not intend to elaborate further on more general risks, they are factors worthy of note that point to increased risks for the Company.

1. <u>Declining Credit Ratings</u>

Q. What is the status of Idaho Power's credit ratings?

A. Idaho Power's credit ratings as of July 31, 2009, are as follows:

	Standard & Poor's	Moody's	Fitch
Corporate Credit Rating	BBB	Baa 1	None
Senior Secured Debt	A-	A3	A-
Senior Unsecured Debt	BBB	Baa 1	BBB+
Short-Term Tax-Exempt Debt	BBB-/A-2	Baa 1/VMIG-2	None
Commercial Paper	A-2	P-2	F-2
Credit Facility	None	Baa 1	None
Rating Outlook	Stable	Negative	Negative

Q. Standard & Poor's ("S&P") downgraded the Company's credit rating in January of 2008. What prompted this action?

A. S&P lowered the corporate credit ratings for both Idaho Power and IDACORP from BBB+ to BBB, citing cash flow concerns, the proposed general rate settlement, and specifically mentioning the impacts of load growth. S&P's research update on January 31, 2008, stated:

> The rating action was driven by a gradual deterioration of cash flow coverage and last week's proposed general rate case settlement, which does not sufficiently address long-term ratemaking issues tied to rising costs and load growth pressures. Over time, average credit metrics have deteriorated, and the company has been unable to stabilize returns and cash flow with existing rate mechanisms. The proposed settlement calls for an average 5.2% rate increase but does not settle some important, policy-related issues in the case, such as the use of a forecasted test year or the appropriate level of the load growth adjustment credit.

Q. Have there been other ratings actions in 2008?

A. Yes. Both Fitch Ratings and Moody's Investors Service ("Moody's") recently changed their ratings outlooks for both Idaho Power and IDACORP from "stable" to "negative" on March 20, 2008, and June 03, 2008, respectively. As recently as July 08, 2009, Moody's reaffirmed their negative outlook on Idaho Power's corporate credit rating. Regarding their continued concern, Moody's stated:

> Key concerns continue to focus on hydro conditions given the persistence of drought conditions during the past decade and higher than historical average planned capital spending despite recent steps to curtail or delay certain projects. Moreover, while key credit metrics are beginning to trend upward, further strengthening of cash flow and continued conservative financing strategies are necessary to allay our concerns and improve the company's weak position within the Baa1 rating category. To accomplish this, continued support from state regulators in anticipated future general rate cases will also remain an important rating driver.

Q. Do you believe that Idaho Power's current credit ratings are adequate?

A. Other utilities with the same credit ratings as Idaho Power are able to raise capital in today's markets. However, these new debt/bond issues are at a higher cost than if these utilities had a higher credit rating (the higher the credit rating, the lower the cost). As a result, the utilities pass on higher interest costs to customers over the life of the bonds. In addition, the financial crisis of 2008 significantly widened the gap between costs for highly rated debt and lower rated debt. In a recent discussion with Idaho Power, J.P. Morgan presented data indicating that the cost differential between A-rated 10-year utility bonds and BBB-rated 10-year utility bonds changed from 34 basis points in mid-2007 to 200 basis points in 2009. That is a six-fold increase in the cost relative to that credit rating differential. In simple terms, today lower rated credit is much more costly.

One large threat to Idaho Power's current ratings is unforeseen risk. Should an unforeseen event cause Idaho Power's short-term credit ratings to be lowered, the Company would no longer be able to issue commercial paper. This would limit the options Idaho Power has available to meet on-going cash requirements, such as funding capital improvements and paying for deviations in power supply costs, and would likely result in higher interest costs to the customer. The unforeseen risk has a potentially greater impact when a company is closer to the bottom of what is considered "investment grade."

Q. What is the lowest rating that is considered investment grade?

A. For S&P that rating is BBB-. Idaho Power's corporate credit rating is currently one step above that bottom rating. Its senior unsecured debt rating is actually at that bottom level and its secured debt rating is currently at A-. A significant concern for me, as the officer primarily responsible for providing the Company's capital, is how close Idaho Power is to the bottom of investment grade status. The concern is heightened by the Company's need to raise increasing amounts of capital in the near future for some fundamental infrastructure improvements. The last time Idaho Power faced this situation it carried much better credit ratings than today.

Q. Can you illustrate the recent trend in ratings for the Company and show the relationship to the level that is considered investment grade?

A. Yes. I have included Exhibit No. 301 which clearly shows the downward trend to Company ratings and shows how close the current ratings are to the bottom level for investment grade companies.

2. <u>Reasonable Actual Results</u>

Q. Do you have an opinion as to why the rating agencies have taken their recent actions to reduce Idaho Power's credit ratings?

A. Yes, I do. I believe that the single largest contributor is the fact that Company's actual results have been significantly below its allowed rate of return.

Q. Has the Company been able to earn its allowed return on equity in recent years?

A. No. In 2005, Idaho Power's authorized Oregon return on equity was 10.0 percent and the Company only earned 7.7 percent on a total system basis. In 2006, Idaho

Power's actual return on equity was higher but still barely over 9 percent in a year that enjoyed *good hydro conditions*. In 2007, Idaho Power earned an actual return on equity of 6.9 percent and in 2008 the return on equity was slightly higher at 7.9 percent. In fact, the actual return on equity for the Company has not been above 10 percent since 2002.

The gap between allowed and actual becomes even more pronounced when the Oregon jurisdiction is isolated. Since 2002, the implied return on equity for the Oregon retail jurisdiction has never reached 6 percent. From 2005 through 2008, this implied return on equity declined steadily from 4.3 percent to a negative 3.6 percent. I have included Exhibit No. 302 to illustrate this gap between actual and allowed earnings in recent years.

Q. How is this continual earnings short-fall perceived in the financial community?

A. I believe that the financial community and the rating agencies are both focused on and concerned about this short-fall. Recent ratings actions are looking directly at the actual results of Idaho Power's regulatory efforts. Both the financial community and the ratings agencies expect realized rates of return to be near allowed levels, or at least to occur at or above allowed levels as often as they fall below them. They are both also looking for more consistency in cash flows.

Q. What are the impacts if ratings agencies and financial markets are continually disappointed with actual results?

A. The impact is that the Company and its customers eventually incur higher costs of capital. Lower ratings actions contribute to higher costs of debt while dissatisfaction in the financial markets can mean lower stock valuation, which leads to greater numbers of equity share issuances, ultimately driving total cost of capital higher.

3. <u>Hydro Variability</u>

Q. Please describe the risks specific to Idaho Power's predominately hydroelectric generating base.

A. Idaho Power and its customers have historically enjoyed the benefits of a hydroelectric-based utility. The availability of hydroelectric power depends on the amount of snow pack in the mountains upstream of Idaho Power's hydroelectric facilities, reservoir storage, springtime snow pack run-off, rainfall, temperature and other weather variability, combined with other stream flow management considerations. During low water years, when stream flows into Idaho Power's hydroelectric projects are reduced, Idaho Power's hydroelectric generation is reduced. Extreme temperatures increase demand for power by customers who use electricity for cooling and heating and moderate temperatures decrease demand for power. Precipitation or the lack thereof also directly affects the Company's irrigation load. Weather and hydro-production are inextricably linked. Reduced hydroelectric generation resulting from below normal water flows requires the Company to use more expensive thermal generation and/or purchased power to meet the electrical needs of its customers.

Q. Are there any other water or weather-related risks of the Company that you would like to comment on?

A. Yes. Comments from credit rating agencies and analysts have expressed concern about the potential impacts from aquifer recharge and water rights. The Company's reliance on hydro generation in general has come under scrutiny with recent history delivering so many below-normal water years in our region. Some of the water issues affecting Idaho Power occur primarily in the Idaho service territory but they impact the general risk profile of the Company. While it is difficult to quantify potential exposures, the heightened level of discussions and disagreements regarding water related issues have increased the Company's risk profile in the financial community.

4. <u>Power Cost Volatility</u>

Q. Do the Company's established mechanisms for handling variations in

power supply costs remove this weather and water risk?

A. Not entirely. Although both of Idaho Power's regulatory jurisdictions provide mechanisms for recovery of variations in power supply expense, the recovery is less than 100 percent. Since the established mechanisms do not insulate the Company from the effects of 100 percent of all power cost variations, larger variations translate to more volatility for financial results. This higher volatility is viewed as elevated risk by the financial community.

Q. Why have the earnings stability benefits of the power cost adjustment mechanisms to the Company declined?

A. While I do not profess to be an expert on the details of these mechanisms, from a financial perspective, I can identify one significant factor that has materially affected earnings stability.

Q. Please elaborate.

A. Our first power cost adjustment mechanism was established for the Idaho jurisdiction in 1993. At that time, there was a fundamental relationship between FERC jurisdictional rates for purchases and sales and Idaho Power retail rates. All of the prices or rates were cost-based.

In 1997, FERC determined that it would permit market-based rates as opposed to cost-based rates. While both the Company's Idaho and Oregon retail rates remained cost-based, FERC jurisdictional rates for sales and purchases became market-based. As a result, the cost or price for both FERC jurisdictional power purchases and sales attributable to Idaho Power increased significantly. The result is that monetary amounts for purchased power and surplus sales have been many times greater since market-based rates have been in effect. The exposure to these larger variations in power supply costs has had a significant financial impact on Idaho Power. While the Company's power cost mechanisms in both Idaho and Oregon offer mitigation from these impacts, the protection is not 100 percent. The financial community and rating agencies continue to factor a heightened risk level to hydro related power cost variations.

Q. Has anyone in the financial community tried to quantify the risks relative to hydro exposure for the Company?

A. Yes. While all of the rating agencies and much of the equity analyst community have commented on the significant level of risk the Company faces in regard to its high reliance on hydro power, S&P actually reviewed the hydro issue specifically for Northwest utilities.

On January 28, 2008, S&P issued a report titled "Pacific Northwest Hydrology and Its Impact On Investor-Owned Utilities' Credit Quality." This report took an in-depth look at hydro implications for investor owned utilities in the Northwest. Specifically regarding Idaho Power, S&P stated that "Idaho Power's regulatory mechanisms are strong, relative to the other companies in our survey, but not strong enough to overcome significant exposure to the variable flows of the Snake River." The report went on to indicate the financial implications to the Company related to this and other factors as described below:

> Despite having both a PCA and an update process, the mechanisms have not been able to fully insulate the company from the highly variable and generally low flow conditions that have persisted on the Snake River for the greater part of the past decade. Idaho Power's financial performance has been also hampered by a load growth adjustment mechanism that has resulted in a cash loss on new customers, and regulatory lag due to the use of a historical test year for the non-fuel component of rates.

5. <u>Relicensing the Hells Canyon Complex</u>

Q. Please describe the risks associated with the renewal of federal licenses for the Company's hydroelectric projects.

A. Idaho Power is the only investor-owned electric utility in the United States that, under normal water conditions, derives 55 percent of its generation from hydro generating facilities. With such a large percentage of the Company's generation resources reliant on hydro facilities, a failure to successfully renew the federal licenses of these facilities could have a significant financial impact on the Company and the prices its consumers pay for electricity. For this reason, the Company has committed to expend significant financial and human resources to obtain new licenses for its hydro generating capacity from the Federal Energy Regulatory Commission ("FERC.")

Q. What are the financial risks associated with the Company's efforts to relicense its hydro generating facilities?

A. Once an application is filed, the utility has no idea as to how long it will be before an order is received from the FERC. This uncertainty, combined with the potential loss of generation capability due to operational changes, and the magnitude of the financial impact of unknown Protection, Mitigation, and Enhancement ("PM&E") costs are financial risks to the Company.

Q. Are there other hydro relicensing-based financial risks considered by the investment community?

A. Yes. For any particular generating facility, the worst possible outcome would be the loss of the license to a competing party. Along with the uncertainty as to the eventual receipt of licenses and the costs involved in preparing for the license applications, costs of PM&E related to these projects are also difficult to quantify. The potential financial magnitude of these PM&E costs and their affect on the Company's low-cost hydro generation resources threaten the financial stability of a company the size of Idaho Power and the ultimate rates it must charge its customers. These amounts will vary among facilities; however, in all cases, they can be significant due to lost generation capacity, generation at a higher cost, and the decreased ability of the Company to time and control water releases.

If the Company cannot generate when it is most advantageous for the system, then some of the economic value of the generation will be lost even if the amount of total generation does not change. In addition to the hydro relicensing risk, the Company continually faces significant capital, operating, and other costs relating to compliance with current environmental statutes, rules, and regulations. These costs may be even higher in the future as a result of, among other factors, changes in legislation and enforcement policies and the potential additional requirements imposed in connection with the relicensing of the Company's hydroelectric projects.

Q. Please address the risk specifically associated with the Company's relicensing effort before the FERC for the Hells Canyon generating facilities.

A. The Hells Canyon generating facilities – comprised of Hells Canyon, Oxbow, and Brownlee dams – make up 67 percent of the Company's hydro generation capacity and 40 percent of its total generation capacity. The Hells Canyon license application was filed in July 2003 and accepted by the FERC for filing in December 2003. The FERC process moves at a slow and deliberate pace due to the large number of interested parties involved in evaluating the application; therefore, the timing of the issuance of a new Hells Canyon facilities license remains uncertain. Historically, FERC has given the Company an annual license renewal (under the existing old license) until the formal new license is issued. It is difficult to predict the ultimate financial impact of the relicense until the new FERC license is issued and all of the relicense conditions are known.

Q. Please comment on the relicensing efforts that the Company has already undertaken.

A. As part of the FERC relicensing regulations and pursuant to the Federal Power Act, the Company is required to conduct numerous studies and evaluations concerning botanical issues, land management issues, hydraulic issues, flow modeling issues, sedimentary issues, water quality issues, aquatic issues, recreation issues, cultural resource issues, and fish and wildlife issues.

Q. How does the Company account for the cost of these projects?

A. Idaho Power books the project costs to Construction Work in Progress ("CWIP") because they are part of the relicensing process pursuant to FERC and state accounting requirements. While the costs are included in CWIP, the Company accrues a capitalization charge commonly referred to as an Allowance for Funds Used during Construction ("AFUDC"). The AFUDC is a non-cash item that represents the cost of related debt and equity financing. The component for AFUDC attributable to borrowed funds is included as a reduction to interest expense, while the equity component is included in other income. The total amount of AFUDC is charged to CWIP.

Q. What will occur when the Company receives a new license for the Hells Canyon facilities?

A. The amounts in CWIP will be transferred to plant in service and the accumulation of AFUDC will cease. The result will be a large increase in rate base with earnings of the Company declining since there will be no AFUDC. Because this is a relicense of an existing hydro facility, there will be no increase (if not a decrease due to operational changes) in the generation of power and thus no increase in sales revenues. The financial industry sees this as a risk that confronts the Company which can be summarized as follows: upon receipt of a relicense, (1) the Company's earnings will go down (no AFUDC), (2) the Company's rate base will go up (transfer from CWIP), and (3) no additional sales revenues (same plant but new license). If the completion of relicensing is not aligned perfectly with the allowance of new effective rates that recognize the transfer of previously deferred relicensing costs into rate base, the Company will be harmed. For the period of time the new rate base is under review by the Commission, the Company will earn no return on roughly $100 million of investment. This probable lag combined with the potential for some disallowance is a significant risk factor.

6. Qualifying Facility ("<u>QF") Concerns</u>

Q. Does the regulatory treatment of the Company's energy purchases from

PURPA QFs increase the financial risk to Idaho Power?

A. Yes. The regulatory treatment of QF expenditures provides for a one-for-one recovery of dollars expended, but does not provide for a return to compensate the Company for this activity. The Company is, in effect, buying and selling energy pursuant to a legal mandate, without any compensation for providing this service. Simplistically, this regulatory treatment is similar to requiring a person operating a business to buy a product at the same price it must be sold. The mere dollar-for-dollar recovery of QF expenditures, with no return for the use of the Company's balance sheet and liquidity in managing QF programs, is viewed as a significant risk by the rating agencies. The rating agencies are not making a judgment related to the appropriateness of QF energy purchase programs, but merely pointing out the cost of the financial risk(s) arising from a QF transaction, and that this risk should be reflected in a higher return on equity to credit the Company for its QF contracts.

Q. Do the rating agencies recognize the financial costs of QF-related transactions?

A. Yes. Like other electric utilities, when the Company adds to its rate base, it must use some portion of shareholder equity to fund the investment. The Company must maintain its proportion of equity to debt above a certain level as it continues this investment process. If it does not, the debt level increases and the Company will face the threat of a bond rating downgrade. Conversely, when the Company enters into a QF contract for purchased power, an obligation not reflected in its financial statements, an increase in equity is needed to maintain credit quality. Unless an equity component is provided to offset the debt-like obligation of long-term QF purchase power contracts, the Company faces off-balance sheet financial risk. For financial commitments that do not appear on the balance sheet, credit rating analysts impute the debt and interest equivalents on the financial statements of the Company to achieve a more accurate picture of the risk associated with the investment and the Company's related commitment. The added equity needed to offset this imputed debt and interest represents the effect that long-term purchased power commitments have on the cost of capital. Any increase in the long-term obligation of a utility related to its capacity and energy resources will have to be backed by an appropriate amount of equity in the eyes of the investment community.

In reviewing its evaluation of the credit implications of QF-related expenditures, in May of 2003, S&P noted that such agreements are "debt-like in nature" and that the increased financial risk must be considered in evaluating a utility's credit risks.

> Standard & Poor's Ratings Services views electric utility purchased-power agreements (PPA) as debt-like in nature, and has historically capitalized these obligations on a sliding scale known as a 'risk spectrum.' Standard & Poor's applies a 0% to 100% 'risk factor' to the net present value (NPV)of the PPA capacity payments, and designates this amount as the debt equivalent.
>
> * * *
>
> Standard & Poor's evaluates the benefits and risks of purchased power by adjusting a purchasing utility's reported financial statements to allow for more meaningful comparisons with utilities that build generation. Utilities that build typically finance construction with a mix of debt and equity. A utility that leases a power plant has entered into a debt transaction for that facility; a capital lease appears on the utility's balance sheet as debt. A PPA is a similar fixed commitment. When a utility enters into a long-term PPA with a fixed-cost component, it takes on financial risk. Furthermore, utilities are typically not financially compensated for the risks they assume in purchasing power, as purchased power is usually recovered dollar-for-dollar as an operating expense.

Q. Are QF-related expenditures really that material?

A. Yes. Idaho Power currently has 91 contracts with QFs representing 458 megawatts ("MW") of capacity. Seventy-nine QF projects are operating with a nameplate capacity of 298 MW. In 2008, the Company made payments of approximately $46 million to QF projects. QF expense is a material risk factor for Idaho Power.

7. <u>Growth and Reliability</u>

Q. Please describe the risks relative to the Company's ability to recover

significant capital investment required for present and growing electrical requirements.

A. As the Company's generation and transmission systems age and customer electrical requirements increase, additional investment is required to meet reliability standards and the additional demand on its electrical infrastructure. The Company's first quarter 2009 Form 10Q projects a construction budget of between $220 to $230 million in 2009 and between $780 million to $800 million of new construction expenditures over the three-year period of 2009 through 2011. The roughly $800 million new construction estimate includes only the siting and permitting costs related to several major transmission expansions and excludes roughly $400 million of capital costs relating to the construction of the proposed Langley Gulch power plant. Construction investments of this magnitude introduce two elements of risk. First, the ability of the Company to attract the required capital and, second, the recovery of these investments is on a deferred basis and subject to the regulatory process.

Q. What affect does growth have on this element of risk?

A. Growth inherently worsens the effects. Operation & Maintenance ("O&M") expenses typically rise faster than inflation and new plant additions often suffer some period of zero percent return awaiting eventual rate base treatment.

Q. Has the Company been able to earn its authorized return on equity during recent years?

A. No. In fact, the Company's actual total system return on equity has been less than 9 percent for the last 5 years. The implied return on equity for the Oregon jurisdiction has actually been below 5 percent for this same five-year period.

Q. Hasn't growth slowed substantially with the recent recession?

A. Growth has certainly slowed but it has by no means halted. Demands for new capital relating to both growth and reliability remain significant in size and a burden to the Company, even though some reductions have been realized, particularly in regard to new customer hook-ups. In my opinion, the Company still bears significant risk meeting its obligation to serve customers and continues to feel the pressure to raise large amounts of growth-related capital requirements. Additionally, efforts at the national level to reshape energy policy may place new upward pressure on spending. New policies will most likely bring additional spending requirements to meet renewable portfolio standards and to comply with expected carbon reducing efforts now being considered.

CAPITAL STRUCTURE

Q. Would you please describe Exhibit No. 303?

A. Exhibit No. 303 details the calculation of Idaho Power's capital structure for long-term debt, the common equity balance resulting from the Company's forecasted year-end 2009 capital structure as provided to me by Company witness Catie Miller, and the resulting overall rate of return that I am recommending.

Q. The capital structure presented on Exhibit No. 303 incorporates changes to the Company's financial reporting of its capital structure. Could you please discuss the rationale for the variance?

A. For financial reporting purposes, the American Falls Bond Guarantee and the Milner Dam Note Guarantee are included in the long-term debt portion of the capital structure. For ratemaking purposes, the interest costs associated with both the American Falls and the Milner debt securities are treated as O&M expenses. Even with these exclusions, the capital structure presented in my Exhibit No. 303 is reasonable in light of industry and rating agency criteria.

Q. Would you please comment on Exhibit No. 304?

A. Exhibit No. 304 details the calculation of the cost of debt used in the estimated year-end 2009 capital structure. The cost of debt is 6.131 percent. In addition, the Company assumed that the Sweetwater and Humboldt County bonds would be remarketed in a fixed mode before the end of the year. Idaho Power averaged quotes from two investment banks for similarly rated bonds. These rates were estimated at the time the overall cost of capital rates were needed to prepare a rate case filing.

Q. Does the Company utilize variable rate securities in its long-term capitalization?

A. Yes. The Company currently utilizes one variable rate security in its long-term capitalization. The Port of Morrow (Boardman) Pollution Control Revenue Bonds Variable Rate Series 2000 ($4.36 million) is listed on line 19 of the exhibit.

Q. Would you please describe the variable rate nature of this pollution control bond?

A. This variable rate pollution control bond, although considered a long-term security, has features that allow the Company to take advantage of rates applicable to short-term securities. The interest rate is determined the first day of a weekly period by a Remarketing Agent. The Remarketing Agent examines tax-exempt obligations comparable to the Boardman Variable Bonds known to have been priced or traded under the then-prevailing market conditions and finds the lowest rate which would enable sale of the Boardman Variable Rate Bonds.

Q. How did you determine what rate to use for the Boardman Variable Rate Bond?

A. I used the average rate observed for this specific bond in 2008.

Q. Please comment on the structure and rates for the Humboldt and Sweetwater County bonds and how they differ from the last rate case.

A. In the last rate case, the Sweetwater and Humboldt County bonds were in an auction rate mode that reset periodically (every seven days for Sweetwater and every 35 days for Humboldt). The mode had produced short-term rates for the long-dated securities even lower than the Boardman Variable rate bonds and these benefits have been passed on to the customer through a lower overall cost of capital structure since 2003. However, in February of 2008, the entire auction rate market began to deteriorate rapidly based on overall credit worries in the market, specifically around the mono-line insurers which guarantee a large portion of the debt in this market. Both the Sweetwater and Humboldt bonds began to experience much higher reset rates through the auction process (e.g., between 7 and 10 percent for Sweetwater). The Company arranged for a short-term loan and used the proceeds to purchase these bonds and hold them in Idaho Power's name. This is a temporary solution, although a second short-term loan had to be negotiated due to the significant financial disruptions in 2008. The Company expects to remarket these bonds in a longer term-fixed mode before the current short-term loan expires in February of 2010.

OVERALL COST OF CAPITAL

Q. What is the overall cost of capital for Idaho Power?

A. As shown on Exhibit No. 303, using the projected year-end 2009 capital structure provided to me by Ms. Miller, the cost of capital presented in my testimony, and incorporating the 11.25 percent cost of equity, the resultant overall cost of capital for Idaho Power is 8.68 percent.

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

A. Yes, it does.

Idaho Power/301
Witness: Steven R. Keen

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

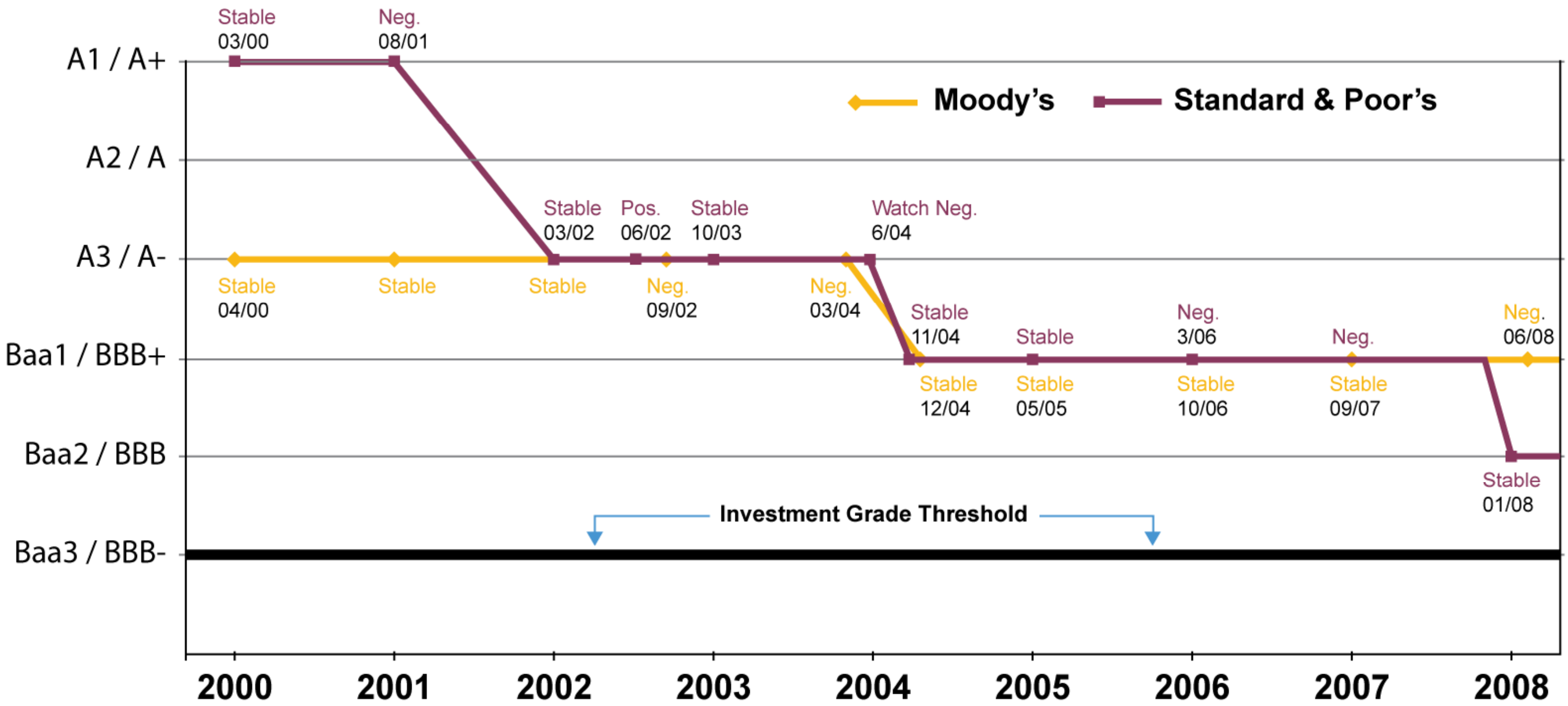
IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Steven R. Keen
Idaho Power Credit Rating History

July 31, 2009

Idaho Power
Credit Rating History

Moody's / S&P



BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

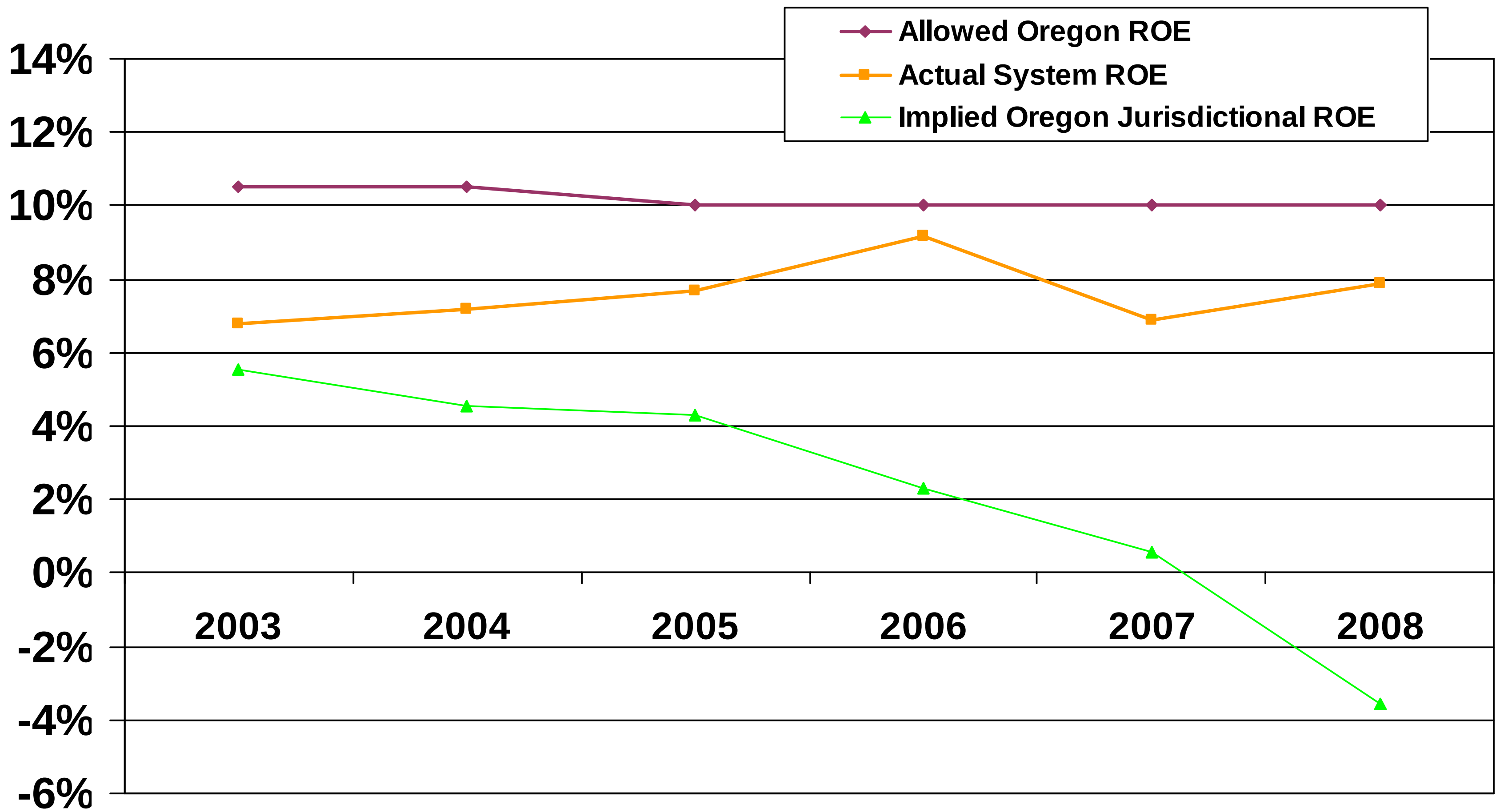
IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Steven R. Keen
Oregon Return on Equity

July 31, 2009

Oregon Return on Equity

Oregon Retail Jurisdiction



Idaho Power– Allowed Vs. Actual Return on Equity 2003-2008

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Steven R. Keen
Pro Forma Cost of Capital Summarized

July 31, 2009

IDAHO POWER COMPANY

PRO FORMA COST OF CAPITAL
SUMMARIZED
December 31, 2009 Capitalization

	(1)	(2)	(3)	(4)	(5)
Line No		Capitalization Structure Amount	Percent	Embedded Cost	Weighted Cost
1	Long-term Debt	1,255,460,000	50.204%	6.131%	3.078%
2	Preferred Stock	0	0.000%	0.000%	0.000%
3	Common Equity	1,245,277,972	49.796%	11.250% *	5.602%
4	Total Capitalization	$2,500,737,972	100.000%		8.680%

Note:
* Requested Rate of Return

Idaho Power/304
Witness: Steven R. Keen

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Steven R. Keen
Pro Forma Cost of Long-Term Debt

July 31, 2009

IDAHO POWER COMPANY
PRO FORMA COST OF LONG-TERM DEBT
As of 12/31/2009
(000's)

Line No.	(1) Class and Series	(2) Coupon Rate	(3) Settlement Date	(4) Maturity Date	(5) Principal Amount Issued	(6) Principal Amount Outstanding	(7) Price	(8) Discount	(9) Issuance Costs	(10) Net Proceeds	(11) Yield To Maturity	(12) Effective Cost
	First Mortgage Bonds:											
1	6.60% Series, due 2011	6.60%	3/2/2001	3/2/2011	120,000	120,000	100.000	0.0	871.3	119,128.7	6.70%	7,982.6
2	4.75% Series, due 2012	4.75%	11/15/2002	11/15/2012	100,000	100,000	98.948	1,052.0	1,066.2	97,881.8	5.02%	4,915.7
3	6.00% Series, due 2032	6.00%	11/15/2002	11/15/2032	100,000	100,000	99.456	544.0	1,191.2	98,264.8	6.13%	6,020.8
4	4.25% Series, due 2013	4.25%	5/13/2003	10/1/2013	70,000	70,000	99.465	374.5	641.2	68,984.3	4.43%	3,052.8
5	5.5% Series, due 2033	5.5%	5/13/2003	4/1/2033	70,000	70,000	99.948	36.4	4,335.2	65,628.4	5.95%	3,904.2
6	5.5% Series, due 2034	5.5%	3/26/2004	3/15/2034	50,000	50,000	99.233	383.5	524.4	49,092.1	5.63%	2,761.9
7	5.875% Series, due 2034	5.875%	8/16/2004	8/15/2034	55,000	55,000	98.640	748.0	585.8	53,666.2	6.05%	3,247.4
8	5.30% Series, due 2035	5.30%	8/26/2005	8/15/2035	60,000	60,000	99.319	408.6	3,849.7	55,741.7	5.80%	3,234.2
9	6.30% Series, due 2037	6.30%	6/22/2007	6/15/2037	140,000	140,000	99.801	278.6	1,500.0	138,221.4	6.40%	8,840.1
10	6.25% Series, due 2037	6.25%	10/18/2007	10/15/2037	100,000	100,000	99.732	268.0	1,227.5	98,504.5	6.36%	6,267.1
11	6.025% Series, due 2018	6.025%	7/10/2008	7/15/2018	120,000	120,000	100.000	0.0	1,664.6	118,335.4	6.21%	7,352.1
12	6.15% Series, due 2019	6.15%	3/30/2009	4/1/2019	100,000	100,000	99.815	185.0	1,252.1 [4]	98,562.9	6.35%	6,255.0
13												
14	Total First Mortgage Bonds				1,085,000	1,085,000		4,278.6	18,709.3	1,062,012.1	6.01%	63,833.9
15												
16	Pollution Control Revenue Bonds:											
17	Sweetwater Series 2006, due 2026 [1]	6.55%	10/3/2006	7/15/2026	116,300	116,300	100.000	0.0	7,342.9 [5]	108,957.1	7.15%	7,790.3
18	Humboldt Series 2003, due 2024 [2]	6.35%	10/22/2003	12/1/2024	49,800	49,800	100.000	0.0	2,259.6 [6]	47,540.4	6.76%	3,211.7
19	Port of Morrow Series 2000, due 2027 [3]	Variable	5/17/2000	2/1/2027	4,360	4,360	100.000	0.0	170.3	4,189.7	3.19%	133.7
20												
21	Total Pollution Control Revenue Bonds				170,460	170,460		0.0	9,772.8	160,687.2	6.93%	11,135.7
22												
23	TOTAL DEBT CAPITAL				1,255,460	1,255,460		4,278.6	28,482.2	1,222,699.2	6.13%	74,969.6

[1] Forecasted rate, assuming conversion to fixed rate mode in June 2009. Rates are an average of indicative pricing as of 4/22/09.
[2] Forecasted rate, assuming conversion to fixed rate mode in June 2009. Rates are an average of indicative pricing as of 4/22/09.
[3] Variable Rate based on 2008 actual interest. See Cost of Long-Term Variable Rate Debt schedule.
[4] Includes estimated issuance expenses - $2,195,000 estimated total shelf expense prorated (100/350) = $627,143.
[5] Includes estimated issuance expenses - $1,690,000 estimated total issuance expense prorated (116.3/166.1) = $1,183,000.
[6] Includes estimated issuance expenses - $1,690,000 estimated total issuance expense prorated (49.8/166.1) = $507,000.
NOTE: American Falls Dam Bond and Milner Dam Note are guarantees. These instruments are excluded from rate making calculations and therefore are omitted from this schedule.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE _________

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE IN THE STATE OF OREGON.	))))))

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

DOUGLAS N. JONES

July 31, 2009

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

A. My name is Doug Jones and my business address is 1221 West Idaho Street, Boise, Idaho. I am employed by Idaho Power Company ("Idaho Power" or "Company") as the Regulatory Accounting and Support Team Leader.

Q. What is your educational background?

A. I graduated in 1980 from Boise State University, Boise, Idaho, receiving a Bachelor of Business Administration degree in Accounting. I have also attended numerous accounting and regulatory courses, including the University of Wisconsin-Madison's School of Business Center for Public Utilities Electric Rates Advanced Rate Making Course and the University of New Mexico's College of Business and Economics Center for Public Utilities Basic Rate Making Course.

Q. Please outline your business experience with Idaho Power.

A. From 1993 to 2002, I was employed by Idaho Power in the Property Accounting Department as an accountant. From 2002 to 2006, I served as a Financial Analyst and later as a Business Analyst in the Financial Reporting Department under the Regulatory Accounting and Support Area. In this area, I was responsible for modeling, analyzing, and recording of the Power Cost Adjustments and deferrals in both Idaho and Oregon, respectively. I was also responsible for overseeing all regulatory audits, preparing regulatory analysis, and disclosures both internally and for the Company's external quarterly and annual reports. In July 2006, I was promoted to Team Leader of Regulatory Accounting and Support in the Strategic Analysis Department.

Q. What are your duties as Team Leader of Regulatory Accounting and Support?

A. I am responsible for all areas of regulatory reporting and act as the finance liaison to the Pricing and Regulatory Services Department.

Q. Could you briefly summarize how the Company has developed its 2009 test year ("2009 Test Year" or "Test Year")?

A. Yes. The development of the 2009 Test Year begins with 2008 actual financial data ("2008 Actuals"). 2008 Actuals were adjusted for traditional ratemaking adjustments to arrive at 2008 adjusted actual financial information ("2008 Base"). The 2008 Base is then adjusted to reach 2009 forecasted financial levels ("2009 Unadjusted Forecast Year"). Finally, traditional and other ratemaking adjustments were made to the 2009 Unadjusted Forecast Year to reach the Company's 2009 Test Year. The adjustments to get from the 2008 Base to the 2009 Test Year will be addressed in Company witness Catherine Miller's testimony.

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

A. The purpose of my testimony is two-fold. First, I will present the Company's historical actual audited financial information for the twelve-month period ended December 31, 2008. Second, my testimony will identify certain adjustments to operating expenses and rate base that result in an adjusted historical actual twelve-month period ended December 2008 ("2008 Base").

Q. Please describe the manner in which the 2008 Actuals and 2008 adjustments are presented?

A. 2008 Actuals and 2008 adjustments are presented using the account names from the Commission-approved Uniform System of Accounts ("USA"). The components include the following items: (1) other operating revenues; (2) other revenues and expenses; (3) operation and maintenance expenses; (4) property insurance expenses; (5) regulatory commission expenses; (6) depreciation and amortization expenses; (7) amortizations, adjustments, gains, and losses; (8) regulatory debits and credits; (9) taxes other than income taxes; (10) Idaho Energy Resources Company ("IERCo") Statement of Income and Rate Base Components; (11) electric plant in service and related items; (12) materials and supplies; (13) deferred conservation programs; (14) other deferred programs; (15) plant held for future use; (16) deferred income taxes; (17) customer advances for construction; and (18) certain deductions from operating and maintenance expenses.

Q. Please describe the types of adjustments you have made to the 2008 actual data.

A. The adjustments to 2008 Actuals to arrive at the 2008 Base are what I describe as standard regulatory adjustments, with the exception of Plant Held for Future Use.

Plant Held for Future Use as of December 31, 2008, has been included and adjusted to remove structures and specific properties for which the future use is uncertain (e.g., subject to being divided for partial use or removed due to the possible change in need for the property). The rationale for inclusion of Plant Held for Future Use and the adjustments is discussed later in my testimony.

The Company has made adjustments to remove expenses as previously directed by either the Idaho Public Utilities Commission ("IPUC" or "Idaho Commission") or Public Utility Commission of Oregon ("Commission" or "OPUC"). The result is a consistent treatment in both Idaho and Oregon jurisdictions. These adjustments include the removal of general advertising expenses, specific memberships and contributions, certain management expenses, and other exclusions that, although justified for business purposes, may be viewed as inappropriate for regulatory recovery. Also removed is the unamortized portion of the Electric Plant Amortization Adjustment associated with the Prairie Power Rural Electric Cooperative purchase, all 2008 incentive compensation, the financial impacts of the Idaho Energy Efficiency Rider revenues and expenses, and, finally, the removal of specific Idaho Intervenor funding amortization that was authorized for recovery from the Company's Idaho jurisdiction.

Q. Are you sponsoring exhibits that detail the 2008 Actuals and 2008 adjustments by the components you have just identified?

A. Yes. I am sponsoring Exhibit Nos. 401 through 403 that detail the 2008 actual data and adjustments by component categories

Q. Please describe Exhibit No. 401.

A. Exhibit No. 401 is a compilation of the Company's supporting schedules for the adjusted historical actual data for the twelve-month period ended December 2008. Page 1 of Exhibit No. 401 reflects the detail for Other Operating Revenues – Accounts 449, 451, 454, and 456. Page 2 reflects the detail of Other Revenues – Account 415 and Expenses 416. Pages 3 through 6 reflect the Operations and Maintenance Expenses ("O&M") by USA account.

Q. Please describe pages 7 through 13 of Exhibit No. 401.

A. Page 7 of Exhibit No. 401 reflects the detail of Property Insurance Expense, Account 924. Page 8 shows the detail of Regulatory Commission Expenses, Account 928. Pages 9 and 10 include Depreciation and Amortization Expense by plant account. Page 11 of Exhibit No. 401 presents the Prairie Power acquisition amortization adjustment, Account 406, and Gain on Sale of Electric Plant, Account 411.6. Page 12 reflects Regulatory Debits and Credits, Account 407.3 and 407.4, respectively. Page 13 shows the detail of Taxes Other Than Income Taxes.

Q. Please explain the adjustments you have made on page 13 of Exhibit No. 401, Taxes Other Than Income, to arrive at the adjusted 2008 Actuals.

A. The amounts included on lines 1, 2, and 20 of page 13, column 1, in Exhibit No. 401 are eliminated by the State and Federal payroll loading reversal on line 23, column 1. These amounts represent Federal Unemployment, Social Security, and State Unemployment taxes, respectively. The State and Federal payroll loading reversal effectively removes these amounts from Taxes Other Than Income and spreads them over all accounts that receive labor charges. Therefore, the adjustments in column 2, page 13 eliminate these expenses in their entirety from this schedule in order to demonstrate that these amounts are not double counted when determining the Company's revenue requirement.

Q. How does the Company treat IERCo's earnings and investment for rate making purposes?

A. The primary purpose of IERCo is to mine the coal that fuels the Jim Bridger thermal power plant in Wyoming. Consistent with UE 167, the Company treats IERCo's coal operations as a part of its utility operation and accordingly adds the current year IERCo earnings to electric operating income and the investment in IERCo to the net electric rate base. Accordingly, the interest expense net of tax (line 13, page 14 of Exhibit No. 401) on notes payable to Idaho Power has been added back to IERCo's Net Income from Operations. Additionally, the notes payable (column 3, line 14, page 24 of Exhibit No. 401) to Idaho Power have been added to IERCo's rate base in determining the Company's net investment in IERCo to be included in total system rate base.

Q. Please describe page 14 of Exhibit No. 401.

A. Page 14 of Exhibit No. 401 develops the net earnings from IERCo that are added to the Company's recorded operating income for ratemaking purposes.

Q. Why have you made adjustments to IERCo's net earnings and rate base in this proceeding?

A. Adjustments were made to increase IERCo's rate base for notes payable to Idaho Power in the amount of $25,580,108 (column 3, line 14, page 24 of Exhibit No. 401) and the associated interest expense adjustment net of income tax of $627,693 (column 3, line 13, page 14 of Exhibit No. 401) to allow IERCo's rate base and earnings to reflect only the cash required to fund IERCo operations for the year 2008. If IERCo were to use these funds to make a distribution of earnings to the Company, or if the Company were to actually fold IERCo into its own operations, the result would be the same as presented herein.

Q. Please describe the data contained on pages 15 through 24 of Exhibit No. 401?

A. Pages 15 through 24 of Exhibit No. 401 reflect the development of all components applicable to the combined system rate base of the Company for the year 2008. Page 15 reflects the balance by month and the thirteen-month average of Electric Plant in Service , Account 101. Page 16 reflects the balance by month and the thirteen-month average of Accumulated Provision for Depreciation, Account 108. Page 17 reflects the balance by month and the thirteen-month average of Accumulated Provision for Amortization, Account 111. Page 18 reflects the balance by month and the thirteen-month average of Materials and Supplies, Accounts 154 and 163. Pages 19 and Page 20 of Exhibit No. 401 reflect the balance of the Company's Conservation and Other Deferred Programs, respectively. For these programs, the Company has included the December 31, 2008, ending balance in rate base, consistent with UE 167. Page 21 reflects the year-end balance of Plant Held for Future Use, Account 105.

Q. Please describe in more detail Other Deferred Programs on page 20 of Exhibit No. 401.

A. Previous Idaho and Oregon Commission-approved programs included on page 20 of Exhibit No. 401 are the American Falls Bond Refinancing costs (UE 167 and IPC-E-08-10) and Intervenor Funding costs that resulted from the following Idaho cases: (1) the 2005 Idaho general rate case (IPC-E-05-28), (2) the Idaho load growth adjustment case (IPC-E-06-08), (3) the Idaho fixed cost adjustment case (IPC-E-04-15), (4) the Idaho increased wind power rate eligibility cap and elimination of the 90/110 band case (IPC-07-03), and (5) the 2007 Idaho rate case (IPC-E-07-08). The American Falls Bond Refinancing is being amortized over the life of the American Falls bond and will be fully amortized in

2025. The Intervenor Funding costs are being amortized and recovered in the Company's Idaho jurisdiction over one year and will be fully amortized in either 2009 or early 2010.

Also included on Exhibit 401 is the Oregon and the FERC's jurisdictional portion of unrecovered costs of the Grid West Loans.

Q. Please describe in more detail Plant Held for Future Use, Account 105, on page 21 of Exhibit No. 401.

A. Consistent with treatment approved in both the 2007 and 2008 Idaho general rate cases, Case Nos. IPC-E-07-08 and IPC-E-08-10, respectively, the Company has included Plant Held for Future Use as part of its 2008 actual costs. Idaho Code § 61-502(A) allows the Idaho Commission to set rates for utilities that include a rate of return on property held for future use if the Idaho Commission makes an explicit finding that such a return is in the public interest. In preparing this case, the Company performed a review and identified those parcels of land included in Account 105, Plant Held for Future Use, that are anticipated to be used in their entirety for operating property in the future. As a result of this review, the year-end 2008 balance of $6,318,162 has been reduced by $1,340,655 in column 2, line 33 for those properties for which the use is uncertain or may be split to arrive at an adjusted year-end balance of $4,977,507. This amount includes only costs associated with parcels of land, i.e., real property. Any costs associated with structures or any other non-real property have been excluded.

Q. What is your understanding regarding the Commission's treatment of plant held for future use?

A. My understanding is that Oregon has the general requirement that utility plant included in rate base must be used and useful in providing service to customers. However, in this case, the costs included in the case are associated with plant that was necessarily acquired in order to ensure safe and reliable service to Idaho Power customers, and its acquisition was therefore in the public interest. Idaho Power believes that under such circumstances, such costs should, as a matter of policy, be considered to be within the "used and useful" standard.

Q. Why is the acquisition of these properties in the public's interest?

A. Purchasing land for substations and other facilities prior to the time the facilities are constructed benefits the Company and ultimately the customer. With the increased growth in Idaho Power's service territory, it has become increasingly difficult and expensive to compete with developers to acquire strategically located properties as the need arises. As a result, the Company has been forced to look further into the future and acquire those properties necessary for future needs. In addition to the financial benefits, early acquisition of these properties reduces opposition and assists local planners by identifying where Idaho Power's infrastructure will be located.

Q. Why does the Company feel it is appropriate to include a return on Plant Held for Future Use in the Oregon jurisdiction?

A. Unlike Construction Work in Process ("CWIP"), the amount invested and held in Plant Held for Future Use does not accrue an allowance for funds used during construction ("AFUDC") until such a time that actual construction begins and these dollars are transferred into CWIP. Therefore, during the time period that these dollars are held in Plant Held for Future Use, the Company has not been able to recover its cost to finance the acquisition of these properties. The increased lead time necessary in acquiring these properties and the resulting increase in financing costs is becoming problematic.

Q. Please describe the remaining pages in Exhibit No. 401.

A. Page 22 of Exhibit No. 401 reflects the balance at the beginning and end of 2008 and the average balance for Accumulated Deferred Income Taxes, Accounts 190, 281, 282, and 283. Page 23 reflects the balance by month and the thirteen-month average balance of Customer Advances for Construction, Account 252. Page 24 reflects the balance by month and thirteen-month average of the rate base components for IERCo consistent with UE 167.

Q. Please describe Exhibit No. 402.

A. Exhibit No. 402 reflects the detailed support of deductions from the O&M expense of the Company for general advertising expenses, certain memberships and contributions, senior management expenses, and miscellaneous other expenses. These adjustments have been made by the Company consistent with prior orders of the Idaho and/or Oregon Commissions.

Q. Please describe in more detail pages 2 through 10 of Exhibit No. 402.

A. The Company has put processes in place to review and screen its accounting records to identify memberships and contributions in an effort to properly identify, account for, and share the costs of each. In an effort to be consistent in both the Oregon and Idaho jurisdictions, the Company has not only removed 100 percent of specific memberships as it did in the last Oregon general rate case (UE 167). In addition, the Company has also removed 100 percent of all contributions and one-third to 100 percent of other specific memberships as directed by the Idaho Commission. This screening process is consistent with the three previous Idaho general rate case filings. Additionally, and again in an effort to be consistent with directives received from the Idaho Commission, senior management expenses have been reviewed and adjusted by (1) removing 100 percent of all charges to the Arid Club and Oregon jurisdiction direct charges, (2) removing one-third of Edison Electric Institute ("EEI") expenses, and (3) allocating the balance of expense account charges of senior management between Idaho Power and IDACORP on the basis of how their payroll is charged. Four of the officers included in this exhibit required no further allocation based on payroll as their expenses are reviewed and adjusted monthly, ensuring proper allocation between IDACORP and Idaho Power. Lastly, as directed by the Idaho Commission, the Company has reviewed all expense account charges to O&M in an effort to identify and exclude specific purchasing card ("P-Card") charges from regulatory recovery based on concerns expressed in prior Idaho regulatory filings (based solely on the name of the business establishment) that these charges might not be appropriate. While the Company is confident that these expense account charges are legitimate business expenses, out of an abundance of caution, they have been removed.

Q. Why has the Company chosen to include deductions from O&M that have been required by the Idaho Commission but have not been specifically required by the Oregon Commission?

A. Although the Company could have legitimately sought recovery of many of these items in the Oregon jurisdiction, the Company chose to include these deductions, which are required by the Idaho jurisdiction, in an effort to more closely align its two state service territories as well as to maintain a conservative approach.

Q. Please describe Exhibit No. 403.

A. Exhibit No. 403 was developed to identify and include or exclude specific rate base, revenue and expense adjustments which have not been provided for elsewhere. These and/or similar adjustments have been made in previous general rate cases.

Q. Please describe the adjustments you have included in this exhibit.

A. Exhibit No. 403, lines 1 through 3 reflect the unamortized portion of the Electric Plant Acquisition Adjustment associated with the Prairie Power Rural Electric Cooperative purchase in July 1992.

Line 4 of Exhibit No. 403 reflects a decrease to Investment in Associated Companies (IERCo), Account 123, for a portion of plant deemed not used and useful at the Bridger Coal plant, per Idaho Commission Order No. 29505.

Lines 5 and 6 of Exhibit No. 403 remove the income statement impact of the Idaho Energy Efficiency Rider (formerly DSM Rider) ("Energy Efficiency Rider") accounting affecting Other Electric Revenues, Account 456, and Customer Assistance Expenses, Account 908, in accordance with Idaho Commission Order No. 30189. While the purpose of these entries is to demonstrate that the Idaho Energy Efficiency Rider revenues and expenses have been excluded from the revenue requirement, leaving these amounts in the income statement would have had no impact to the revenue requirement since they are a net zero adjustment.

Line 7 of Exhibit No. 403 removes all 2008 incentives included in Administrative and General Salaries, Account 920, since they are being addressed as a known and measurable adjustment in Ms. Miller's testimony.

Lines 8 through 10 of Exhibit No. 403 records the removal of amortization expense included in Regulatory Commission Expenses, Account 928, for amounts included in the 2007 test year for recovery that resulted from Idaho Commission Order Nos. 30035, 30215, and 30267.

Q. Are all the data and associated adjustments made to your exhibits and supporting schedules calculated on a total system basis?

A. Yes.

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

A. Yes, it does.

Idaho Power/401
Witness: Douglas N. Jones

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Douglas N. Jones
Actual 2008 Financial Information

July 31, 2009

IDAHO POWER COMPANY
OTHER OPERATING REVENUES
For Twelve Months Ended December 31, 2008

Line No	Description	(1) Y-T-D Actuals Dec 2008	(2) Adjustment	(3) 2008 Base
1	Miscellaneous service revenues (451)...........	$ 3,669,976		$ 3,669,976
	Rent from electric property (454):			
2	Substation equipment.........................	7,114,492		7,114,492
3	Transformer & distribution rentals...........	17,330		17,330
4	Station and line rentals.....................	2,039,614		2,039,614
5	Cogeneration and small power production......	546,786		546,786
6	Real estate rents............................	330,426		330,426
7	Dark fiber rents.............................	447,360		447,360
8	Joint pole attachments.......................	1,505,132		1,505,132
9	Facilities charges...........................	6,561,257		6,561,257
10	Overnight park rents.........................	327,242		327,242
11	Miscellaneous................................	-		-
12	Total rent from electric property.........	18,889,639		18,889,639
	Other electric revenue (456):			
13	Network services.............................	5,411,638		5,411,638
14	Point - to - Point and other services........	12,911,651		12,911,651
15	Photovoltaic.................................	11,601		11,601
16	Antelope.....................................	73,824		73,824
17	Conservation recovery - Oregon..............	-		-
18	Sierra Pacific Power Company sales...........	103,087		103,087
19	Stand-by service	288,494		288,494
20	Transmission services for IES	-		-
21	Energy efficiency rider	18,880,276		18,880,276
22	Miscellaneous................................	75,647		75,647
23	Total other electric revenue.............	37,756,218	-	37,756,218
24	Provision for rate refund - OATT Tariff (449)..	(9,979,836)	9,979,836	-
25	Total other operating revenues.................	$ 50,335,997	$ 9,979,836	$ 60,315,833

IDAHO POWER COMPANY
OTHER REVENUES AND EXPENSES
For Twelve Months Ended December 31, 2008

Line No	Program	(1) Y-T-D Actuals Dec 2008	(2) Adjustment	(3) 2008 Base
	Other Revenues (Acct 415):			
1	Power Solutions..............	$ 1,136,449		$ 1,136,449
2	Hydro Services................	-		-
3	Water Management Services.....	254,522		254,522
4	Joint Use (Pole) - Idaho......	130,576		130,576
5	Joint Use (Pole) - Oregon.....	(16,115)		(16,115)
6	Total.....................	$ 1,505,432	$ -	$ 1,505,432
	Other Expenses (Acct 416):			
7	Power Solutions..............	$ 965,885		$ 965,885
8	Hydro Services................	(288)		(288)
9	Water Management Services.....	136,075		136,075
10	Joint Use - Idaho............	102,211		102,211
11	Joint Use - Oregon...........	-		-
12	Total.....................	$ 1,203,883	$ -	$ 1,203,883

IDAHO POWER COMPANY
OPERATION AND MAINTENANCE EXPENSES
For Twelve Months Ended December 31, 2008

LINE NO	FERC ACCOUNT NUMBER	DESCRIPTION	(1) Y-T-D Actuals Dec 2008	(2) Adjustment	(3) 2008 Base
	Power production expenses:				
	Steam power generation -				
	Operation -				
1	500	Oper and supv engineering	$ 1,650,284	$ -	$ 1,650,284
2	501	Fuel	-	-	-
3	502	Steam expenses	7,376,689	-	7,376,689
4	505	Electric expenses	1,817,960	-	1,817,960
5	506	Misc steam power expenses	7,737,497	-	7,737,497
6	507	Rents	469,699	-	469,699
7	Total operation		19,052,129	-	19,052,129
	Maintenance -				
8	510	Main supv and engineering	2,567,722		2,567,722
9	511	Main of structures	398,714		398,714
10	512	Main of boiler plant	14,205,043		14,205,043
11	513	Main of electric plant	4,301,150		4,301,150
12	514	Main of misc steam plant	4,322,931		4,322,931
13	Total maintenance		25,795,560	-	25,795,560
14	Total steam power generation		44,847,689	-	44,847,689
	Hydraulic power generation -				
	Operation -				
15	535	Oper supv and engineering	5,602,490		5,602,490
16	563	Water for power	5,104,001		5,104,001
17	536	Water for power	2,251,740		2,251,740
18	537	Hydraulic expenses	9,978,474		9,978,474
19	538	Electric expenses	1,312,586		1,312,586
20	539	Misc hydro pwr gen exp	3,091,677		3,091,677
21	540	Rents	431,893	-	431,893
22	Total operation		27,772,861	-	27,772,861
	Maintenance -				
23	541	Main supv and engineering	1,885,154	.	1,885,154
24	542	Main of structures	1,362,031		1,362,031
25	543	Main of res,dams,waterwys	808,311		808,311
26	544	Main of electric plant	2,495,503		2,495,503
27	545	Main of misc hydro plant	3,135,803		3,135,803
28	Total maintenance		9,686,802	-	9,686,802
29	Total hydraulic power generation		37,459,663	-	37,459,663
	Other power generation -				
	Operation -				
30	546	Oper supv and engineering	372,614		372,614
31	547	Fuel -Other general fuel	31,915	-	31,915
32	547	Facility charge	308,560	-	308,560
33	547	Fuel	-	-	-
34	548	Generation expenses	404,456		404,456
35	549	Misc other pwr gen exp	530,176		530,176
36	550	Rents	-	-	-
37	Total operation		1,647,721	-	1,647,721

IDAHO POWER COMPANY
OPERATION AND MAINTENANCE EXPENSES
For Twelve Months Ended December 31, 2008

LINE NO	FERC ACCOUNT NUMBER	DESCRIPTION	(1) Y-T-D Actuals Dec 2008	(2) Adjustment	(3) 2008 Base
	Other power generation - (continued)				
	Maintenance -				
1	551	Main supv and engineering	$ 213		$ 213
2	552	Main of structures	162,376		162,376
3	553	Main of gen and elec plt	198,271		198,271
4	554	Main misc oth pwr gen plt	509,219		509,219
5	Total maintenance		870,079	-	870,079
6	Total other power generation		2,517,800	-	2,517,800
	Other power supply expenses -				
7	555	Purchased power	-		-
8	556	System cont and load disp	77,979		77,979
9	557	Other expenses	2,507,103		2,507,103
10	557	Other expenses	-		-
11	Total other power supply expenses		2,585,082	-	2,585,082
12	Total power production expenses		87,410,234	-	87,410,234

IDAHO POWER COMPANY
OPERATION AND MAINTENANCE EXPENSES
For Twelve Months Ended December 31, 2008

LINE NO	FERC ACCOUNT NUMBER	DESCRIPTION	(1) Y-T-D Actuals Dec 2008	(2) Adjustment	(3) 2008 Base
	Transmission expenses:				
	Operation -				
1	560	Oper supv and engineering	$ 2,404,396		$ 2,404,396
2	561	Load dispatching	2,883,995		2,883,995
3	562	Station expenses	1,805,492		1,805,492
4	563	Overhead line expenses	735,577		735,577
5	564	Underground line expenses	-		-
6	565	Trans of elec by others	7,250,299		7,250,299
7	566	Misc trans expenses	465,342		465,342
8	567	Rents	1,085,343		1,085,343
9	Total operation		16,630,444	-	16,630,444
	Maintenance -				
10	568	Main supv and engineering	431,690		431,690
11	569	Main of structures	451,600		451,600
12	570	Main of station equip	2,706,579		2,706,579
13	571	Main of overhead lines	3,367,619		3,367,619
14	573	Main of misc trans plant	272		272
15	Total maintenance		6,957,760	-	6,957,760
16	Total transmission expenses		23,588,204	-	23,588,204
	Distribution expenses:				
	Operation -				
17	580	Oper supv and engineering	3,321,954		3,321,954
18	581	Load dispatching	3,110,301		3,110,301
19	582	Station expenses	1,143,619		1,143,619
20	583	Overhead line expenses	3,346,471		3,346,471
21	584	Underground line expenses	2,034,228		2,034,228
22	585	St light and sgnl sys exp	130,886		130,886
23	586	Meter expenses	4,636,934		4,636,934
24	587	Customer install expenses	1,398,175		1,398,175
25	588	Misc distribution exp	5,464,167		5,464,167
26	589	Rents	456,147		456,147
27	Total operation		25,042,882	-	25,042,882
	Maintenance -				
28	590	Main supv and engineering	319,660		319,660
29	591	Main of structures	2,323		2,323
30	592	Main of station equip	3,534,603		3,534,603
31	593	Main of overhead lines	13,759,196		13,759,196
32	594	Main of underground lines	1,235,321		1,235,321
33	595	Main of line transformers	445,190		445,190
34	596	Main of st lght-sgnl sys	665,088		665,088
35	597	Main of meters	862,862		862,862
36	598	Main of misc dist plant	354,999		354,999
37	Total maintenance		21,179,242	-	21,179,242
38	Total distribution expenses		46,222,124	-	46,222,124

IDAHO POWER COMPANY
OPERATION AND MAINTENANCE EXPENSES
For Twelve Months Ended December 31, 2008

LINE NO	FERC ACCOUNT NUMBER	DESCRIPTION	(1) Y-T-D Actuals Dec 2008	(2) Adjustment	(3) 2008 Adjustment
	Customer accounts expenses:				
	Operation -				
1	901	Supervision	$ 341,842		$ 341,842
2	902	Meter reading expenses	5,752,965		5,752,965
3	903	Cust records - collect exp	11,773,960		11,773,960
4	904	Uncollectible accounts	3,671,345		3,671,345
5	904	Uncollectible accounts	10,609		10,609
6	905	Misc customer accts exp	468		468
7	Total customer accounts expenses		21,551,189	-	21,551,189
	Customer service and informational expenses:				
	Operation -				
8	907	Supervision	299,410		299,410
9	908	Customer assistance exp	8,794,465		8,794,465
10	908	Energy efficiency rider	18,880,276		18,880,276
11	909	Info and instruct adv exp	-		-
12	910	Misc cust svc and inf exp	860,302		860,302
13	912	Demo and selling exp	-		-
14	Total customer service and informational expenses		28,834,453	-	28,834,453
	Administrative and general expenses:				
	Operation -				
15	920	Admin and gen salaries	42,088,764		42,088,764
16	920	Incentive	15,448,509		15,448,509
17	921	Office supplies and exp	14,791,346		14,791,346
18	922	Admin exp transf - cr	(22,736,029)		(22,736,029)
19	923	Outside services employed	13,597,223		13,597,223
20	924	Property insurance	3,103,669		3,103,669
21	925	Injuries and damages	7,548,140		7,548,140
22	926	Emp pensions and benefits	22,727,495		22,727,495
23	926	Emp pensions and benefits	112,926		112,926
24	927	Franchise requirements	1,549		1,549
25	928	Reg commission expenses	4,832,197		4,832,197
26	929	Duplicate charges - cr	-		-
27	930.1	General advertising exp	236,828		236,828
28	930.2	Misc general expenses	3,515,410		3,515,410
29	931	Rents	6,827		6,827
30	Total operation		105,274,854	-	105,274,854
	Maintenance -				
31	935	Main of general plant	4,149,186		4,149,186
32	Total maintenance		4,149,186	-	4,149,186
33	Total administrative and general expenses		109,424,040	-	109,424,040
34	Total electric operation and maintenance expenses		$317,030,244	$ -	$317,030,244

(1) Grey shaded lines represent power supply costs that are normalized.

IDAHO POWER COMPANY
OPERATION AND MAINTENANCE EXPENSES
PROPERTY INSURANCE - ACCOUNT 924
For Twelve Months Ended December 31, 2008

Line No	Description	(1) Y-T-D Actuals Dec 2008	(2) Adjustment	(3) 2008 Base
	Production - steam:			
1	Bridger plant..............	$ 447,275		$ 447,275
2	Boardman plant.............	44,731		44,731
3	Valmy plant................	354,036		354,036
4	Total production - steam	846,042	-	846,042
	All risk:			
5	Blanket fidelity bond......	64,211		64,211
6	Property "all risk"........	1,960,401		1,960,401
7	Other miscellaneous........	233,015		233,015
8	Total all risk..........	2,257,627	-	2,257,627
9	Total property insurance......	$ 3,103,669	$ -	$ 3,103,669

IDAHO POWER COMPANY
OPERATION AND MAINTENANCE EXPENSES
REGULATORY COMMISSION EXPENSES - ACCOUNT 928
For Twelve Months Ended December 31, 2008

Line No	Description	(1) Y-T-D Actuals Dec 2008	(2) Adjustment	(3) 2008 Base
	FERC administrative assessments and securities (928.101)			
1	Capacity..............................	$ 1,902,421		$ 1,902,421
2	Generation............................	830,277		830,277
3	Ferc Order #472 - Sales for resale.....	341,902		341,902
4	Miscellaneous Other....................	1,176,210		1,176,210
5	Total (928.101)......................	4,250,810	-	4,250,810
6	FERC - Rate Case (928.102)..............	32,513		32,513
7	FERC - Oregon Hydro (928.104)...........	158,506		158,506
8	Total FERC expense...................	4,441,829	-	4,441,829
	Idaho Public Utilities Commission expense:			
9	Rate case (928.202)....................	185,052		185,052
10	Other (928.203)........................	13,565		13,565
11	Total IPUC expense...................	198,617	-	198,617
	Oregon Public Utility Commission expense:			
12	Filing Fees (928.301)..................	-		-
13	Rate case (928.302)....................	203		203
14	Other (928.303)........................	191,548		191,548
15	Total OPUC expense...................	191,751	-	191,751
	Nevada Public Service Commission expense:			
16	Other (928.403)........................	-		-
17	Total NPSC expense...................	-	-	-
18	Total regulatory commission expenses.....	$ 4,832,197	$ -	$ 4,832,197

Idaho Power Company
Intelliplant Depreciation System
Depreciation and Amortization Expense
Twelve Months Ending 12/31/08

FERC Account	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08
302	65,088.62	65,087.62	65,088.62	65,087.62	65,088.62	65,087.62
303	371,854.65	374,886.47	376,952.08	377,695.34	377,719.33	391,234.65
Amortization Expense	436,943.27	439,974.09	442,040.70	442,782.96	442,807.95	456,322.27
310	384.10	384.10	384.10	384.10	384.10	384.10
311	283,390.58	283,356.95	283,645.05	283,639.92	283,652.71	284,676.18
312	1,248,746.67	1,249,579.46	1,252,463.68	1,252,830.39	1,254,357.51	1,254,479.48
314	366,619.01	366,561.51	366,914.11	367,191.05	366,156.27	366,120.95
315	110,566.23	110,892.96	111,318.60	111,379.25	111,434.92	111,434.92
316	38,251.57	38,251.57	33,451.75	38,520.97	38,823.24	38,981.81
Total Steam Production	2,047,958.16	2,049,026.55	2,048,177.29	2,053,945.68	2,054,808.75	2,056,077.44
331	286,516.91	287,507.23	287,448.34	287,516.46	287,586.15	288,031.95
332	390,657.30	390,657.54	394,476.32	394,530.67	394,752.79	394,920.19
333	285,985.04	285,876.09	285,801.13	284,789.47	284,849.30	284,993.86
334	89,601.17	90,181.03	90,138.22	91,585.44	94,856.95	94,456.15
335	25,133.10	25,585.38	25,649.10	25,738.32	25,936.93	26,123.92
336	11,930.38	11,930.38	11,930.38	11,930.38	11,930.38	11,930.38
Total Hydro Production	1,089,823.90	1,091,737.65	1,095,443.49	1,096,090.74	1,099,912.50	1,100,456.45
341	13,643.88	13,643.88	13,643.88	24,477.64	24,815.76	24,730.21
342	8,890.52	8,890.52	8,890.52	12,514.90	12,628.02	12,599.40
343	104,633.74	104,633.74	104,633.74	177,459.98	179,855.15	214,912.30
344	86,737.65	86,737.65	86,737.65	120,066.26	121,106.45	85,209.53
345	33,999.59	33,999.59	33,999.59	41,287.76	39,911.81	41,157.06
346	5,420.68	5,431.20	5,431.20	8,950.54	8,640.57	8,612.78
Total Other Production	253,326.06	253,336.58	253,336.58	384,757.08	386,957.76	387,221.28
Total Production	3,391,108.12	3,394,100.78	3,396,957.36	3,534,793.50	3,541,679.01	3,543,755.17
352	42,871.20	43,113.05	43,383.38	43,438.63	43,727.49	43,795.63
353	463,798.12	469,884.61	470,189.50	472,729.24	472,211.09	473,961.33
Transmission Stations	506,669.32	512,997.66	513,572.88	516,167.87	515,938.58	517,756.96
350	45,219.20	45,220.75	45,797.38	45,809.20	47,270.36	46,662.60
354	248,596.55	252,170.84	252,147.49	252,402.96	251,770.76	254,064.31
355	216,484.12	216,538.51	216,638.14	217,658.32	218,028.81	218,936.37
356	228,051.93	230,758.63	230,717.54	232,828.68	233,797.31	233,990.03
359	283.97	283.97	283.97	283.97	283.97	283.97
Transmission Lines	738,635.77	744,972.70	745,584.52	748,983.13	751,151.21	753,937.28
Transmission	1,245,305.09	1,257,970.36	1,259,157.40	1,265,151.00	1,267,089.79	1,271,694.24
361	36,990.93	37,011.29	37,172.38	37,230.03	36,882.43	37,236.24
362	207,350.32	210,771.60	210,847.47	211,231.69	211,865.91	215,053.48
Distribution Stations	244,341.25	247,782.89	248,019.85	248,461.72	248,748.34	252,289.72
364	623,654.11	624,221.74	625,171.69	627,806.28	628,260.40	629,609.50
365	288,434.51	288,740.40	289,181.52	291,199.48	292,103.35	292,438.85
366	78,418.53	78,615.98	79,143.66	79,575.17	79,656.61	79,769.83
367	389,376.08	391,374.59	392,948.51	396,123.91	396,069.57	397,083.98
368	508,509.16	512,409.77	515,894.35	519,778.82	522,249.23	526,111.59
369	165,705.17	166,342.19	166,780.12	167,166.29	167,292.11	167,794.18
370	190,541.47	191,253.72	191,903.48	190,270.02	190,151.54	191,185.31
371	(82,947.62)	20,526.88	11,983.53	15,751.05	13,498.76	2,603.09
373	19,749.14	19,739.65	19,745.57	19,782.83	19,781.59	19,781.90
Distribution Lines	2,181,440.55	2,293,224.92	2,292,752.43	2,307,453.85	2,309,063.16	2,306,378.23
Total Distribution	2,425,781.80	2,541,007.81	2,540,772.28	2,555,915.57	2,557,811.50	2,558,667.95
390	138,787.01	139,600.69	139,704.18	139,961.36	140,350.39	140,404.14
391	516,267.47	561,003.61	592,369.87	595,770.97	613,324.57	624,804.46
392	98.62	98.62	98.62	98.62	98.62	98.62
393	7,066.01	7,066.01	7,052.10	7,153.16	7,153.16	7,153.16
394	30,540.82	30,736.34	31,301.08	31,719.49	31,884.48	32,010.66
395	55,684.82	55,727.43	55,727.43	57,850.99	57,853.19	59,457.61
396	497.57	497.57	497.57	497.57		
397	207,553.89	207,586.71	209,934.14	210,366.77	210,108.51	210,599.83
398	21,433.57	26,110.82	26,109.59	27,556.71	26,050.62	26,170.64
Total General	977,929.78	1,028,427.80	1,062,794.58	1,070,975.64	1,086,823.54	1,100,699.12
Depreciation Expense	8,040,124.79	8,221,506.75	8,259,681.62	8,426,835.71	8,453,403.84	8,474,816.48
on Disallowed	(24,691.61)	(24,691.61)	(24,691.61)	(24,691.61)	(24,691.61)	(24,691.61)
Total Account 403	8,015,433.18	8,196,815.14	8,234,990.01	8,402,144.10	8,428,712.23	8,450,124.87

Idaho Power Company
Intelliplant Depreciation System
Depreciation and Amortization Expense
Twelve Months Ending 12/31/08

FERC Account	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	12 Month Total
302	65,088.62	65,087.62	65,088.62	65,087.62	65,089.62	65,088.62	781,059.44
303	388,044.40	392,192.31	407,485.33	407,504.48	416,052.80	419,707.07	4,701,328.91
Amortization Expense	453,133.02	457,279.93	472,573.95	472,592.10	481,142.42	484,795.69	5,482,388.35
310	384.10	384.10	150.64	267.37	267.37	267.37	4,025.55
311	284,472.84	284,513.06	53,914.95	169,371.16	169,605.25	155,480.56	2,819,719.21
312	1,273,658.39	1,274,980.60	582,437.69	930,934.81	930,834.04	(150,959.32)	12,354,343.40
314	372,379.25	373,457.25	171,500.25	278,323.87	279,687.13	185,084.46	3,859,995.11
315	112,115.46	112,584.92	27,941.10	70,259.58	70,275.23	(83,615.20)	976,587.97
316	38,683.88	38,765.66	39,292.71	40,520.35	42,553.40	(33,184.88)	392,912.03
Total Steam Production	2,081,693.92	2,084,685.59	875,237.34	1,489,677.14	1,493,222.42	73,072.99	20,407,583.27
331	288,292.46	288,704.26	373,293.13	333,340.18	335,235.45	335,730.68	3,679,203.20
332	394,785.04	394,793.08	525,836.61	460,913.96	461,057.33	461,487.60	5,058,868.43
333	286,263.13	286,274.54	309,211.10	297,706.54	297,772.20	297,703.62	3,487,226.02
334	93,056.92	92,643.55	102,560.23	102,509.88	102,403.32	102,775.14	1,146,768.00
335	26,197.10	26,233.42	38,296.30	36,836.62	37,089.01	37,289.72	356,108.92
336	11,930.38	11,930.38	11,838.28	11,884.33	11,884.33	11,884.33	142,934.31
Total Hydro Production	1,100,525.03	1,100,579.23	1,361,035.65	1,243,191.51	1,245,441.64	1,246,871.09	13,871,108.88
341	24,777.64	24,835.24	27,528.58	26,244.49	26,314.77	26,318.88	270,974.85
342	12,605.37	12,608.36	12,981.71	12,815.97	12,826.46	12,827.79	141,079.54
343	217,410.39	217,638.75	250,090.19	234,284.52	234,495.08	234,178.31	2,274,225.89
344	85,294.98	85,322.42	78,653.13	82,180.28	82,276.77	82,289.03	1,082,611.80
345	41,171.24	41,178.32	47,195.71	44,298.66	44,329.40	44,657.46	487,186.19
346	8,688.18	8,642.39	8,699.70	8,691.38	8,701.56	8,702.86	94,613.04
Total Other Production	389,947.80	390,225.48	425,149.02	408,515.30	408,944.04	408,974.33	4,350,691.31
Total Production	3,572,166.75	3,575,490.30	2,661,422.01	3,141,383.95	3,147,608.10	1,728,918.41	38,629,383.46
352	43,851.72	43,857.62	70,409.55	56,494.93	56,492.83	56,885.12	588,321.15
353	485,716.18	485,880.63	457,450.67	470,676.76	471,890.52	489,248.05	5,683,636.70
Transmission Stations	529,567.90	529,738.25	527,860.22	527,171.69	528,383.35	546,133.17	6,271,957.85
350	46,667.03	46,793.40	27,330.68	37,063.06	37,076.14	37,222.35	508,132.15
354	255,177.56	255,351.01	152,966.56	206,032.07	207,474.29	207,839.10	2,795,993.50
355	219,069.61	219,879.82	201,445.98	213,317.66	216,358.96	217,170.68	2,591,526.98
356	235,733.66	236,056.86	227,034.28	235,715.98	238,314.66	238,960.46	2,801,960.02
359	283.97	283.97	236.21	260.09	260.09	260.09	3,288.24
Transmission Lines	756,931.83	758,365.06	609,013.71	692,388.86	699,484.14	701,452.68	8,700,900.89
Transmission	1,286,499.73	1,288,103.31	1,136,873.93	1,219,560.55	1,227,867.49	1,247,585.85	14,972,858.74
361	37,237.94	41,336.32	33,431.67	37,283.62	37,559.08	37,685.93	447,057.86
362	215,601.63	211,567.78	277,897.07	248,228.77	256,159.75	260,635.43	2,737,210.90
Distribution Stations	252,839.57	252,904.10	311,328.74	285,512.39	293,718.83	298,321.36	3,184,268.76
364	632,715.85	633,095.31	502,734.66	572,565.03	572,702.84	573,225.15	7,245,762.56
365	295,382.70	295,881.47	241,901.10	273,338.44	273,982.23	273,760.50	3,396,344.55
366	79,995.85	80,255.92	79,958.70	80,090.40	80,017.72	80,030.10	955,528.47
367	398,330.78	398,294.67	176,204.88	289,441.20	289,757.36	289,869.10	4,204,874.63
368	529,745.20	531,847.62	498,289.84	521,079.21	523,330.35	526,099.19	6,235,344.33
369	168,339.81	168,633.01	113,898.15	141,671.52	142,084.10	142,398.24	1,878,104.89
370	192,105.51	192,683.13	467,038.34	330,079.63	330,648.07	331,269.87	2,989,130.09
371	10,911.68	18,231.30	(15,308.59)	1,464.90	1,479.32	1,483.12	(322.58)
373	19,803.50	19,828.64	8,386.62	14,134.45	14,140.62	14,134.54	209,009.05
Distribution Lines	2,327,330.88	2,338,751.07	2,073,103.70	2,223,864.78	2,228,142.61	2,232,269.81	27,113,775.99
Total Distribution	2,580,170.45	2,591,655.17	2,384,432.44	2,509,377.17	2,521,861.44	2,530,591.17	30,298,044.75
390	142,130.90	141,819.17	132,547.49	137,240.71	137,463.04	137,614.81	1,667,623.89
391	675,990.64	669,926.46	755,565.03	699,358.77	816,509.71	706,352.21	7,827,243.77
392	98.62	98.62	106.04	102.33	102.33	102.33	1,201.99
393	7,153.16	7,174.25	2,658.11	4,922.23	5,017.00	5,234.50	74,802.85
394	32,010.66	32,979.17	5,555.13	19,334.57	19,552.95	19,614.17	317,239.52
395	59,705.84	59,791.70	38,917.62	49,315.58	49,233.75	50,028.29	649,294.25
396							1,990.28
397	210,822.41	216,930.83	56,981.66	137,296.11	137,362.89	137,713.72	2,153,257.47
398	26,734.56	27,197.93	34,546.41	32,798.30	32,894.20	33,338.22	340,941.57
Total General	1,154,646.79	1,155,918.13	1,026,877.49	1,080,368.60	1,198,135.87	1,089,998.25	13,033,595.59
Depreciation Expense	8,593,483.72	8,611,166.91	7,209,605.87	7,950,690.27	8,095,472.90	6,597,093.68	96,933,882.54
on Disallowed	(24,691.61)	(24,691.61)	(24,691.61)	(24,691.61)	(24,691.61)	(24,691.61)	(296,299.32)
Total Account 403	8,568,792.11	8,586,475.30	7,184,914.26	7,925,998.66	8,070,781.29	6,572,402.07	96,637,583.22

IDAHO POWER COMPANY
ELECTRIC PLANT/REGULATORY ASSETS - AMORT.,ADJUST.,GAINS & LOSSES
For Twelve Months Ended December 31, 2008

Line No	Acct No	Program	(1) Y-T-D Actuals Dec 2008	(2) Adjustment	(3) 2008 Base
1	406	Amortization of electric plant acquisition adjustment - Prairie Power.	(22,723)	-	(22,723)
2	411.6	Gain on sale of utility plant	(11,632)	-	(11,632)
3		Total....................	$ (34,355)	$ -	$ (34,355)

IDAHO POWER COMPANY
REGULATORY DEBITS AND CREDITS
For Twelve Months Ended December 31, 2008

Line No	Program	(1) Y-T-D Actuals Dec 2008	(2) Adjustment	(3) 2008 Base
	Regulatory Debits/Credits (Acct407.3/407.4):			
1		$ -	$ -	$ -
2	Total..	$ -	$ -	$ -

IDAHO POWER COMPANY
TAXES OTHER THAN INCOME TAXES
For Twelve Months Ended December 31, 2008

Line No	DESCRIPTION	(1) Y-T-D Actuals Dec 2008	(2) Adjustment	(3) 2008 Base
	Federal taxes:			
1	Unemployment	$ 124,895	$ (124,895)	$ -
2	Social Security	11,476,651	(11,476,651)	-
3	Total federal taxes	11,601,546	(11,601,546)	-
	State, county and local taxes:			
	Real and personal property:			
4	Idaho	10,901,049		10,901,049
5	Oregon	2,052,307		2,052,307
6	Montana	198,721		198,721
7	Wyoming	1,027,339		1,027,339
8	Nevada	883,098		883,098
9	Shoshone-Bannock	68,610		68,610
10	Total real and personal property	15,131,124	-	15,131,124
11	Kilowatt-hour tax - Idaho	1,559,972		1,559,972
	Licenses:			
12	Wyoming	3,075		3,075
13	Nevada	100		100
14	Shoshone-Bannock	150		150
15	Total licenses	3,325	-	3,325
	Regulatory commission:			
16	Idaho	1,728,039		1,728,039
17	Oregon	119,843		119,843
18	Total regulatory commission	1,847,882	-	1,847,882
	Franchise:			
19	Oregon total franchise	541,650		541,650
20	Unemployment - total state	187,750	(187,750)	-
21	Total state, county and local taxes	19,271,703	(187,750)	19,083,953
22	Total other taxes	30,873,249	(11,789,296)	19,083,953
23	Less: State & Fed P/R Loading Reversal	(11,789,296)	11,789,296	-
24	Net other taxes	$ 19,083,953	$ -	$ 19,083,953

IDAHO POWER COMPANY
STATEMENT OF INCOME
FOR IDAHO ENERGY RESOURCES COMPANY
For Twelve Months Ended December 31, 2008

Line No	Description	(1) Y-T-D Actuals Dec 2008	(2) Adjustment	(3) 2008 Base
	Income:			
1	Bridger Coal Company - joint venture..........................	$ 6,771,535		$ 6,771,535
2	Bridger Coal Company - overriding royalties...................	76,533		76,533
3	Interest and dividend income..................................	-		-
4	Taxes Other than Income Taxes.................................	-		-
5	Total income..	6,848,068	-	6,848,068
	Expenses:			
6	Operation expense...	77,637		77,637
7	Income taxes..	1,683,670		1,683,670
8	Provision for deferred income taxes...........................	-		-
9	Intercompany interest expense.................................	965,681		965,681
10	Interest expense..	-		-
11	Total expenses..	2,726,988	-	2,726,988
12	Net income from operations......................................	4,121,080	-	4,121,080
13	Add: Interest expense from notes payable to parent (Net of Tax)..	965,681	(337,988)	627,693
14	Net income (earnings to Idaho Power Company).....................	$ 5,086,761	$ (337,988)	$ 4,748,773

IDAHO POWER COMPANY
ELECTRIC PLANT IN SERVICE (Excluding ARO Entries)
For The Thirteen Months Ended December 31, 2008

Line No	Month	(1) Amount	(2) Adjustment	(3) 2008 Base
1	December, 2007........................	$ 3,791,803,211		$ 3,791,803,211
2	January, 2008.........................	3,789,336,897		3,789,336,897
3	February..............................	3,801,869,197		3,801,869,197
4	March.................................	3,865,854,513		3,865,854,513
5	April.................................	3,875,077,296		3,875,077,296
6	May...................................	3,886,877,983		3,886,877,983
7	June..................................	3,916,882,630		3,916,882,630
8	July..................................	3,922,234,763		3,922,234,763
9	August................................	3,932,871,618		3,932,871,618
10	September.............................	3,953,058,904		3,953,058,904
11	October...............................	3,967,481,497		3,967,481,497
12	November..............................	3,982,920,999		3,982,920,999
13	December..............................	4,025,993,977		4,025,993,977
14	Average............................	$ 3,900,943,345	$ -	$ 3,900,943,345

IDAHO POWER COMPANY
ACCUMULATED PROVISION FOR DEPRECIATION (Excluding ARO Entries)
For The Thirteen Months Ended December 31, 2008

Line No	Month	(1) Amount	(2) Adjustment	(3) 2008 Base
1	December, 2007..........................	$ 1,583,145,519		$ 1,583,145,519
2	January, 2008...........................	1,590,268,870		1,590,268,870
3	February................................	1,596,847,644		1,596,847,644
4	March...................................	1,601,094,418		1,601,094,418
5	April...................................	1,605,812,686		1,605,812,686
6	May.....................................	1,613,704,339		1,613,704,339
7	June....................................	1,618,552,132		1,618,552,132
8	July....................................	1,625,425,576		1,625,425,576
9	August..................................	1,631,812,741		1,631,812,741
10	September...............................	1,636,808,089		1,636,808,089
11	October.................................	1,642,324,242		1,642,324,242
12	November................................	1,640,470,330		1,640,470,330
13	December................................	1,640,492,270		1,640,492,270
14	Average.............................	$ 1,617,442,989	$ -	$ 1,617,442,989

IDAHO POWER COMPANY
ACCUMULATED PROVISION FOR AMORTIZATION (Excluding ARO Entries)
OF ELECTRIC UTILITY PLANT
For The Thirteen Months Ended December 31, 2008

No	Month	(1) Amount	(2) Adjustment	(3) 2008 Base
1	December, 2007........................	$ 38,713,478		$ 38,713,478
2	January, 2008.........................	13,696,055		13,696,055
3	February..............................	14,136,029		14,136,029
4	March.................................	14,578,070		14,578,070
5	April.................................	15,020,853		15,020,853
6	May...................................	15,463,661		15,463,661
7	June..................................	15,919,983		15,919,983
8	July..................................	16,373,116		16,373,116
9	August................................	16,830,396		16,830,396
10	September.............................	17,302,970		17,302,970
11	October...............................	17,775,562		17,775,562
12	November..............................	18,256,705		18,256,705
13	December..............................	18,741,500		18,741,500
14	Average.............................	$ 17,908,337	$ -	$ 17,908,337

IDAHO POWER COMPANY
MATERIALS AND SUPPLIES
For The Thirteen Months Ended December 31, 2008

		(1)	(2)	(3)	(4)	(5)
Line No	Month	Account 154	Account 163	Total	Adjustment	2008 Base
1	December, 2007..........................	$ 41,370,751	$ 1,898,952	$ 43,269,703		$ 43,269,703
2	January, 2008...........................	42,045,541	1,986,830	44,032,371		44,032,371
3	February................................	43,264,332	2,188,721	45,453,053		45,453,053
4	March...................................	44,736,846	3,713,521	48,450,367		48,450,367
5	April...................................	45,218,477	4,116,804	49,335,281		49,335,281
6	May.....................................	44,489,821	4,306,361	48,796,182		48,796,182
7	June....................................	45,032,458	4,699,050	49,731,508		49,731,508
8	July....................................	44,906,641	5,178,819	50,085,460		50,085,460
9	August..................................	45,288,599	5,400,087	50,688,686		50,688,686
10	September...............................	45,422,311	5,901,471	51,323,782		51,323,782
11	October.................................	44,546,920	5,858,078	50,404,998		50,404,998
12	November................................	43,874,086	5,823,943	49,698,029		49,698,029
13	December................................	44,405,727	5,715,442	50,121,169		50,121,169
14	Average	$ 44,200,193	$ 4,368,314	$ 48,568,507		$ 48,568,507

IDAHO POWER COMPANY
DEFERRED CONSERVATION PROGRAMS
At December 31, 2008

Line No	Program	(1) Actuals Dec 2008	(2) Adjustment	(3) 2008 Base
	IDAHO -			
1	Deferred Conservation - IPUC Order 27660 / 27722 / 28041..........	$ 4,863,935		$ 4,863,935

IDAHO POWER COMPANY
OTHER DEFERRED PROGRAMS
At December 31, 2008

Line No	Program	(1) Actuals Dec 2008	(2) Adjustment	(3) 2008 Base
	Idaho Public Utilities Commission:			
	Account 186			
1	American Falls Bond Refinancing - IPUC Order 25880.............	$ 1,011,247		$1,011,247
	Account 182			
2	Intervenor Funding - Idaho Irrigators (IPUC Order No. 30035)....	6,276		6,276
3	Intervenor Funding - NW Energy Coalition (IPUC Order No. 30215).	1,218		1,218
4	Intervenor Funding - NW Energy Coalition (IPUC Order No. 30267).	1,500		1,500
5	Intervenor Funding - NW Energy Coalition (IPUC Order No. 30488).	25,988		25,988
6	Intervenor Funding - Idaho Irrigators (IPUC Order No. 30508)....	42,326		42,326
	Oregon Public Utilities Commission:			
7	Grid West Loans - OPUC Order 06-483............................	64,994		64,994
	Federal Energy Regulatory Commission:			
8	Grid West Loans..	363,117		363,117
9	Total...	$ 1,516,666	$ -	$1,516,666

Idaho Power Company
Plant Held for Future Use
At December 31, 2008

Line No.		(1) Y-T-D Actuals Dec 2008	(2) Adjustment	(3) 2008 Base
	Power Production:			
1	American Falls Power Plant	$ 104,155	$ (104,155)	$ -
2	Wiley, A J Power Site	8,548	(8,548)	-
3	Total Power Production	112,703	(112,703)	-
	Distribution:			
4	Amity Substation	153,751	-	153,751
5	Beacon Light Substation	465,662	(465,662)	-
6	Boise Mechanical and Electrical Shop	47,000	(47,000)	-
7	BOC Operations Center (BOC)	841,162	(72,785)	768,377
8	Cherry Substation	99,708	(99,708)	-
9	Columbia Station	103,955	-	103,955
10	Filer Substation	27,813	-	27,813
11	Jump Substation	67,722	(22,299)	45,423
12	Kimberly Substation	15,097	-	15,097
13	Lakeshore Substation	188,565	-	188,565
14	Lansing Substation	57,483	-	57,483
15	Melba Substation	29,321	-	29,321
16	North River Operations Center	2,630,412	-	2,630,412
17	State Substation	121,046	(23,840)	97,206
18	Ustick Substation	19,670	(19,670)	-
19	Wagner Substation	91,452	-	91,452
20	Ward Substation	243,933	-	243,933
21	Total Distribution	5,203,752	(750,964)	4,452,788
	Transmission:			
22	Boise Bench Transmission Station	179,905	-	179,905
23	Castlerock Transmission Station	4,024	-	4,024
24	Donnelly McCall Transmission Land R/W	68,620	-	68,620
25	Dry Creek Transmission Station	29,380	-	29,380
26	Homedale Transmission Station	325,172	(215,719)	109,453
27	Long Valley Transmission Station	22,377	-	22,377
28	Mayfield Transmission Station	220,052	(178,094)	41,958
29	Midpoint Transmission Station	73,257	(73,257)	-
30	Sage Transmission Station	69,002	-	69,002
31	Shellrock Transmission Station	9,918	(9,918)	-
32	Total Transmission	1,001,707	(476,988)	524,719
33	Total Plant Held for Future Use	$ 6,318,162	$ (1,340,655)	$ 4,977,507

IDAHO POWER COMPANY
Deferred Income Tax Balances
At 12/31/2008 and 12/31/2007

Description	December 31 2008	December 31 2007	Average Bal. (Rounded)
Deferred income taxes applicable to rate base components:			
Account 190:			
Advances for Construction	9,305,479.05	10,171,997.85	9,738,738.00
Provision for Rate Refunds	5,217,171.07	937,172.05	3,077,172.00
VEBA Payments and Accruals	4,929,292.29	4,056,404.55	4,492,848.00
Rate Case Disallowance	2,996,869.81	3,112,707.91	3,054,789.00
FAS 123R-Stock Based Compensation	2,316,810.74	1,333,711.47	1,825,261.00
Other Employee's LT Deferred Comp	1,829,071.70	2,590,725.18	2,209,898.00
Post employment Benefits - SFAS 112 -182	1,044,455.76	1,184,641.05	1,114,548.00
Non-VEBA Pension and Benefits	662,313.05	762,810.30	712,562.00
Linden Feeder Deposits	0.00	164,403.47	82,202.00
Bonus Deferral	(6,306.02)	(56,181.86)	(31,244.00)
Delivery Accruals	(5,646.49)	129,130.02	61,742.00
Total Account 190	28,289,510.96	24,387,521.99	26,338,516.00
Account 281 - Accelerated amortization property:			
Total Account 281 - Accelerated amortization pr	0.00	0.00	0.00
Account 282 - Other property			
Depreciation	(238,722,105.88)	(215,117,207.59)	(226,919,657.00)
FERC jurisdictional - SGM	0.00	(7,818,502.00)	(3,909,251.00)
Valmy capitalized items	(580,766.00)	(657,266.00)	(619,016.00)
Bridger capitalized items	(17,657.00)	(120,057.00)	(68,857.00)
Total Account 282 - Other property	(239,320,528.88)	(223,713,032.59)	(231,516,781.00)
Account 283 - Other			
Conservation Programs - Idaho	(1,901,555.39)	(3,169,251.42)	(2,535,403.00)
Advance coal royalties	(239,738.36)	(247,769.26)	(243,754.00)
IPUC Grid West Loans	(218,660.67)	(291,547.83)	(255,104.00)
FERC Grid West Expense	(141,960.59)	(118,112.64)	(130,037.00)
PS & I Costs - Coal and CHP Plants - Write Off	(62,711.88)	(100,967.54)	(81,840.00)
Intervener Funding Orders	(30,223.17)	(20,565.53)	(25,394.00)
OPUC Grid West Loans	(25,409.80)	(23,616.13)	(24,513.00)
Incremental Security Costs	0.00	(26,895.00)	(13,448.00)
Total - Account 283 - Other	(2,620,259.86)	(3,998,725.35)	(3,309,493.00)
Total Accounts (190, 281, 282, 283)	(213,651,277.78)	(203,324,235.95)	(208,487,758.00)

IDAHO POWER COMPANY
CUSTOMER ADVANCES FOR CONSTRUCTION
For The Thirteen Months Ended December 31, 2008

Line No	Month	(1) Amount	(2) Adjustment	(3) 2008 Base
1	December, 2007..........................	$ 33,261,676		$ 33,261,676
2	January, 2008...........................	32,551,445		32,551,445
3	February................................	32,969,995		32,969,995
4	March...................................	32,442,155		32,442,155
5	April...................................	31,788,828		31,788,828
6	May.....................................	31,902,671		31,902,671
7	June....................................	31,976,625		31,976,625
8	July....................................	31,562,687		31,562,687
9	August..................................	31,567,745		31,567,745
10	September...............................	31,468,906		31,468,906
11	October.................................	31,072,121		31,072,121
12	November................................	30,613,794		30,613,794
13	December................................	30,033,657		30,033,657
14	Average.............................	$ 31,785,562	$ -	$ 31,785,562

IDAHO POWER COMPANY
IERCo - SUBSIDIARY RATE BASE COMPONENTS
For The Thirteen Months Ended December 31, 2008

Line No	Month	(1) Investment	(2) Advance Coal Royalties	(3) Notes Receivable from Subsidiary	(4) Total	(5) Adjustment	(6) 2008 Base
1	December, 2007................	$ 55,937,107	$ 1,657,049	$ 21,527,626	$ 79,121,782		$ 79,121,782
2	January, 2008................	54,945,865	1,657,049	23,774,134	80,377,048		80,377,048
3	February......................	54,599,834	1,632,736	23,697,860	79,930,430		79,930,430
4	March.........................	55,434,761	1,621,323	26,331,059	83,387,143		83,387,143
5	April.........................	54,900,274	1,615,679	26,520,507	83,036,460		83,036,460
6	May...........................	54,142,725	1,609,981	29,101,655	84,854,361		84,854,361
7	June..........................	54,566,041	1,604,562	30,324,678	86,495,281		86,495,281
8	July..........................	54,744,350	1,603,839	30,014,361	86,362,550		86,362,550
9	August........................	55,755,300	1,603,839	27,581,437	84,940,576		84,940,576
10	September.....................	57,406,332	1,595,825	24,080,573	83,082,730		83,082,730
11	October.......................	58,430,920	1,589,266	21,653,544	81,673,730		81,673,730
12	November......................	59,290,806	1,585,179	21,354,202	82,230,187		82,230,187
13	December......................	60,058,187	1,580,516	26,579,771	88,218,474		88,218,474
14	Average...................	$ 56,170,192	$ 1,612,065	$ 25,580,108	$ 83,362,365	$ -	$ 83,362,366

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Douglas N. Jones
Deductions from O&M Expense

July 31, 2009

IDAHO POWER COMPANY
DEDUCTIONS FROM OPERATION AND MAINTENANCE EXPENSES
GENERAL ADVERTISING EXPENSE (ACCOUNT 930.1)
For Twelve Months Ended December 31, 2008

Line No	Program	(1) Y-T-D Actuals Dec 2008	(2) Adjustment	(3) 2008 Base
1	General Advertising Expense......................	$ 236,828	$ -	$ 236,828

IDAHO POWER COMPANY
DEDUCTIONS FROM OPERATION AND MAINTENANCE EXPENSES
MEMBERSHIPS AND CONTRIBUTIONS
For Twelve Months Ended December 31, 2008

			(1)	(2)	(3)	(4)	(5)	(6)
			Actual					
Line	Acct		Contributions	Memberships				2008
No	No	Organization	100.00%	33.33%	100.00%	Total	Adjustment	Base
1	535	Ecological Society.........................	$ -	$ 20	$ -	$ 20		$ 20
2	537	Oregon Chapter.............................	-	-	105	105		105
3	537	Oregon Department of Agriculture............	-	-	268	268		268
4	539	Oregon State Sheriffs Association...........	-	-	50	50		50
5	539	YMCA Baker.................................	150	-	-	150		150
6	541	Halfway....................................	600	-	-	600		600
7	541	Oregon Department of Agriculture............	-	-	100	100		100
8	545	Halfway....................................	1,350	-	-	1,350		1,350
9	545	Oregon Department of Agriculture............	-	-	50	50		50
10	571	International Society of Arboriculture......	-	60	-	60		60
11	580	Association of Idaho Cities.................	-	(82)	-	(82)		(82)
12	580	Edison Electric Institute...................	-	428	-	428		428
13	580	The National Arbor Society..................	-	110	-	110		110
14	582	Edison Electric Institute...................	-	183	-	183		183
15	586	Chamber of Commerce Nampa...................	-	417	-	417		417
16	586	Education Direct............................	-	342	-	342		342
17	586	Rotary Club................................	-	9	-	9		9
18	586	Rotary Club Pocatello.......................	-	44	-	44		44
19	587	Chamber of Commerce Magic Valley............	-	117	-	117		117
20	587	Rotary Club................................	-	64	-	64		64
22	588	Donations..................................	(33)	-	-	(33)		(33)
23	588	International Society of Arboriculture......	-	22	-	22		22
24	588	Rotary Club McCall..........................	-	89	-	89		89
25	593	Arbor Day	5,443	-	-	5,443		5,443
26	593	Donations..................................	111	-	-	111		111
27	593	International Society of Arboriculture......	-	120	-	120		120
28	593	The National Arbor Society..................	-	219	-	219		219
29	902	Edison Electric Institute...................	-	217	-	217		217
30	907	Rotary Club................................	-	124	-	124		124
31	907	Rotary Club Pocatello.......................	-	201	-	201		201
32	908	Associated Tax Payers.......................	-	-	(300)	(300)		(300)
33	908	Association of Idaho Cities.................	-	497	-	497		497
34	908	Bouquet Express............................	40	-	-	40		40
35	908	Chamber of Commerce Magic Valley............	-	112	-	112		112
36	908	Chamber of Commerce Twin Falls..............	-	100	-	100		100
37	908	City Club of Boise..........................	-	9	-	9		9
38	908	Donations..................................	(82)	-	-	(82)		(82)
39	908	Kiwanis Club...............................	-	25	-	25		25
40	908	Kiwanis Club Les Bois.......................	-	197	-	197		197
41	908	Lions Club Idaho City.......................	-	61	-	61		61
42	908	Lions Club Jordon Valley....................	-	10	-	10		10
43	908	Lions Club Twin Falls.......................	-	145	-	145		145
44	908	Rotary Club................................	-	724	-	724		724
45	908	Rotary Club Boise Centennial................	-	83	-	83		83
46	908	Rotary Club Boise Sunrise...................	-	238	-	238		238
47	908	Rotary Club Caldwell........................	-	67	-	67		67
48	908	Rotary Club Nampa...........................	-	55	-	55		55
49	910	Chamber of Commerce Boise Metro.............	-	27	-	27		27
50	910	Chamber of Commerce Magic Valley............	-	5	-	5		5
52	910	Kiwanis Club...............................	-	20	-	20		20
53	910	Kiwanis Club Eagle..........................	-	10	-	10		10
54	910	Kiwanis Club Les Bois.......................	-	48	-	48		48
55	921	Associated Tax Payers.......................	-	-	420	420		420
56	921	Association of Idaho Cities.................	-	15	-	15		15
57	921	Chamber of Commerce Boise Metro.............	-	67	-	67		67
58	921	Donations..................................	300	-	-	300		300
59	921	Edison Electric Institute...................	-	3,856	-	3,856		3,856
60	921	Greater Pocatello...........................	-	33	-	33		33

IDAHO POWER COMPANY
DEDUCTIONS FROM OPERATION AND MAINTENANCE EXPENSES
MEMBERSHIPS AND CONTRIBUTIONS
For Twelve Months Ended December 31, 2008

			(1)	(2)	(3)	(4)	(5)	(6)
			Actual					
Line	Acct		Contributions	Memberships				2008
No	No	Organization	100.00%	33.33%	100.00%	Total	Adjustment	Base
61	921	Montana Tax Foundation......................	-	-	780	780		780
62	921	National Association of Property Tax........	-	8	-	8		8
63	921	Nevada Taxpayer Association.................	-	-	600	600		600
64	921	Toastmasters................................	-	-	29	29		29
65	930	Air Force Appreciation Days.................	100	-	-	100		100
66	930	Associated Tax Payers of Idaho..............	-	-	21,252	21,252		21,252
67	930	Association of Idaho Cities.................	-	88	-	88		88
68	930	Baker County Unlimited......................	-	-	985	985		985
69	930	Cabelas.....................................	74	-	-	74		74
70	930	Caldwell Economic Development Contribution..	2,500	-	-	2,500		2,500
71	930	Cambridge Commercial Club...................	-	10	-	10		10
72	930	Car Wash Show...............................	100	-	-	100		100
73	930	Castleford Men's Club Contribution..........	100	-	-	100		100
74	930	Chamber of Commerce.........................	-	3,894	-	3,894		3,894
75	930	Chamber of Commerce Annual Banquet Sponsor..	275	-	-	275		275
76	930	Chamber of Commerce Blackfoot...............	-	172	-	172		172
77	930	Chamber of Commerce Boise Metro.............	-	8,161	-	8,161		8,161
78	930	Chamber of Commerce Buhl....................	-	107	-	107		107
79	930	Chamber of Commerce Caldwell................	-	557	-	557		557
80	930	Chamber of Commerce Easter Egg Event........	100	-	-	100		100
81	930	Chamber of Commerce Fundraiser..............	2,475	-	-	2,475		2,475
82	930	Chamber of Commerce Garden City.............	-	250	-	250		250
83	930	Chamber of Commerce Gem County..............	-	550	-	550		550
84	930	Chamber of Commerce Gooding/Wendell.........	-	133	-	133		133
85	930	Chamber of Commerce Hailey..................	-	136	-	136		136
86	930	Chamber of Commerce Idaho City..............	-	33	-	33		33
87	930	Chamber of Commerce Idaho Falls.............	-	71	-	71		71
88	930	Chamber of Commerce Jerome..................	-	270	-	270		270
89	930	Chamber of Commerce McCall..................	-	181	-	181		181
90	930	Chamber of Commerce Meridian................	-	167	-	167		167
91	930	Chamber of Commerce Pocatello...............	-	749	-	749		749
92	930	Chamber of Commerce Salmon..................	-	83	-	83		83
93	930	Chamber of Commerce Sponsorship.............	1,750	-	-	1,750		1,750
94	930	Chamber of Commerce Star....................	-	267	-	267		267
95	930	Chamber of Commerce Sun Valley..............	-	200	-	200		200
96	930	Chamber of Commerce Twin Falls..............	75	-	-	75		75
97	930	Chamber of Commerce Twin Falls..............	-	300	-	300		300
98	930	Chamber of Commerce Weiser..................	-	100	-	100		100
99	930	City Club of Boise..........................	-	200	-	200		200
100	930	Dairy Days..................................	1,250	-	-	1,250		1,250
101	930	Donation to Bannock Development Corporation.	100	-	-	100		100
102	930	Donations...................................	988	-	-	988		988
103	930	Donnelly Fall Fundraiser....................	300	-	-	300		300
104	930	Eastern Oregon Renewable....................	-	-	40	40		40
105	930	Eastern Oregon Visitors Association.........	-	-	1,500	1,500		1,500
106	930	Economic Development........................	-	800	-	800		800
107	930	Economic Development Contribution...........	1,500	-	-	1,500		1,500
108	930	Edison Electric Institute...................	-	124,012	-	124,012		124,012
109	930	Fred Meyers.................................	64	-	-	64		64
110	930	Fruitland Family Donation...................	300	-	-	300		300
111	930	Golf	1,000	-	-	1,000		1,000
112	930	Hagerman Blues Contribution.................	250	-	-	250		250
113	930	Idaho Association of Commerce...............	-	3,333	-	3,333		3,333
114	930	Idaho Association of Counties...............	1,255	-	-	1,255		1,255
115	930	Idaho Economic Development Gift.............	50	-	-	50		50
116	930	Idaho Mining Association....................	-	-	6,960	6,960		6,960
117	930	Idaho Smart Growth Sponsorship..............	500	-	-	500		500
118	930	Jet Boat Race...............................	250	-	-	250		250
119	930	Joe Mama's Car Show.........................	500	-	-	500		500
120	930	Kiwanis Club................................	-	(45)	-	(45)		(45)
121	930	Kiwanis Club Eagle..........................	-	62	-	62		62
122	930	Kiwanis Club Les Bois.......................	-	(20)	-	(20)		(20)
123	930	Lions Club Twin Falls.......................	-	33	-	33		33
124	930	McCall Carnival.............................	1,000	-	-	1,000		1,000
125	930	NIRI..	-	-	576	576		576
126	930	Ontario Development Corporation.............	-	-	55	55		55
127	930	Oregon State Sheriffs Association...........	-	-	50	50		50
128	930	Rotary Club.................................	-	(625)	-	(625)		(625)
129	930	Rotary Club Boise Centennial................	-	221	-	221		221
130	930	Rotary Club Boise Sunrise...................	-	110	-	110		110
131	930	Rotary Club Buhl............................	-	87	-	87		87
132	930	Rotary Club Eagle Garden City...............	-	202	-	202		202
133	930	Rotary Club Hailey..........................	-	433	-	433		433
134	930	Rotary Club Jerome..........................	-	183	-	183		183
135	930	Rotary Club Nampa...........................	-	24	-	24		24
136	930	Rotary Club Twin Falls......................	-	134	-	134		134
137	930	Sandy's Flower Bouquet......................	51	-	-	51		51
138	930	Sportsman's Warehouse.......................	123	-	-	123		123
139	930	Staples.....................................	30	-	-	30		30
140	930	State of the City Address...................	-	100	-	100		100
141	930	Thundermountain Days........................	500	-	-	500		500
142	930	Wide World of Golf..........................	170	-	-	170		170
143	930	Wyoming Tax Payers Association..............	-	-	1,500	1,500		1,500
144		Total.................................	$ 25,609	$ 154,839	$ 35,020	$ 215,468		$ 215,468

IDAHO POWER COMPANY
DEDUCTIONS FROM OPERATION AND MAINTENANCE EXPENSES
ADJUSTMENT TO MANAGEMENT EXPENSES
For Twelve Months Ended December 31, 2008

No	Name	(1) Y-T-D Actuals Dec-08	(2) Adjustment	(3) 2008 Base
1	**Darrel Anderson**			
2	Total Expenses..	$ 17,683		
3	IDACORP Exclusions Requiring Special Treatment (Listed Below):			
4	Arid Club..	-		
5	EEI..	(4,147)		
6	Oregon Direct Charges...............................	-		
7	Total...	13,536		
8	Payroll Percentage Allocated to IDACORP.............	8.70%		
9	Net IDACORP Exclusions................................	1,178		
10	Other Exclusions:			
11	Arid Club (100% Per IPUC Order 29505)................	-		
12	Oregon - Direct Allocation (100%)....................	-		
13	EEI (1/3 Per IPUC Order 29505).......................	1,382		
14	Total Exclusions......................................	$ 2,560		$ 2,560
15	**Naomi Crafton-Shankel**			
16	Total Expenses..	$ 974		
17	IDACORP Exclusions Requiring Special Treatment (Listed Below):			
18	Arid Club..	-		
19	EEI..	-		
20	Oregon Direct Charges...............................	-		
21	Total...	974		
22	Payroll Percentage Allocated to IDACORP.............	4.70%		
23	Net IDACORP Exclusions................................	46		
24	Other Exclusions:			
25	Arid Club (100% Per IPUC Order 29505)................	-		
26	Oregon - Direct Allocation (100%)....................	-		
27	EEI (1/3 Per IPUC Order 29505).......................	-		
28	Total Exclusions......................................	$ 46		$ 46
29	**John Gale**			
30	Total Expenses..	$ 13,337		
31	IDACORP Exclusions Requiring Special Treatment (Listed Below):			
32	Arid Club..	-		
33	EEI..	(4,610)		
34	Oregon Direct Charges...............................	(171)		
35	Total...	8,556		
36	Payroll Percentage Allocated to IDACORP.............	0.00%		
37	Net IDACORP Exclusions................................	-		
38	Other Exclusions:			
39	Arid Club (100% Per IPUC Order 29505)................	-		
40	Oregon - Direct Allocation (100%)....................	171		
41	EEI (1/3 Per IPUC Order 29505).......................	1,537		
42	Total Exclusions......................................	$ 1,708		$ 1,708

IDAHO POWER COMPANY
DEDUCTIONS FROM OPERATION AND MAINTENANCE EXPENSES
ADJUSTMENT TO MANAGEMENT EXPENSES
For Twelve Months Ended December 31, 2008

No	Name	(1) Y-T-D Actuals Dec-08	(2) Adjustment	(3) 2008 Base
43	**Dennis Gribble**			
44	Total Expenses..	$ 16,972		
45	IDACORP Exclusions Requiring Special Treatment (Listed Below):			
46	Arid Club...	-		
47	EEI...	-		
48	Oregon Direct Charges...............................	-		
49	Total...	16,972		
50	Payroll Percentage Allocated to IDACORP.............	0.00%		
51	Net IDACORP Exclusions................................	-		
52	Other Exclusions:			
53	Arid Club (100% Per IPUC Order 29505)................	-		
54	Oregon - Direct Allocation (100%)....................	-		
55	EEI (1/3 Per IPUC Order 29505).......................	-		
56	Total Exclusions......................................	$ -		$ -
57	**Lisa Grow**			
58	Total Expenses..	$ 2,690		
59	IDACORP Exclusions Requiring Special Treatment (Listed Below):			
60	Arid Club...	-		
61	EEI...	-		
62	Oregon Direct Charges...............................	-		
63	Total...	2,690		
64	Payroll Percentage Allocated to IDACORP.............	0.00%		
65	Net IDACORP Exclusions................................	-		
66	Other Exclusions:			
67	Arid Club (100% Per IPUC Order 29505)................	-		
68	Oregon - Direct Allocation (100%)....................	-		
69	EEI (1/3 Per IPUC Order 29505).......................	-		
70	Total Exclusions......................................	$ -		$ -
71	**Patrick Harrington**			
72	Total Expenses..	$ 608		
73	IDACORP Exclusions Requiring Special Treatment (Listed Below):			
74	Arid Club...	-		
75	EEI...	-		
76	Oregon Direct Charges...............................	-		
77	Total...	608		
78	Payroll Percentage Allocated to IDACORP.............	4.90%		
79	Net IDACORP Exclusions................................	30		
80	Other Exclusions:			
81	Arid Club (100% Per IPUC Order 29505)................	-		
82	Oregon - Direct Allocation (100%)....................	-		
83	EEI (1/3 Per IPUC Order 29505).......................	-		
84	Total Exclusions......................................	$ 30		$ 30

IDAHO POWER COMPANY
DEDUCTIONS FROM OPERATION AND MAINTENANCE EXPENSES
ADJUSTMENT TO MANAGEMENT EXPENSES
For Twelve Months Ended December 31, 2008

No	Name	(1) Y-T-D Actuals Dec-08	(2) Adjustment	(3) 2008 Base
85	**LaMont Keen**			
86	Total Expenses..	$ 15,632		
87	IDACORP Exclusions Requiring Special Treatment (Listed Below):			
88	Arid Club...	-		
89	EEI...	(4,139)		
90	Oregon Direct Charges...............................	-		
91	Total...	11,493		
92	Payroll Percentage Allocated to IDACORP.............	4.00%		
93	Net IDACORP Exclusions................................	460		
94	Other Exclusions:			
95	Arid Club (100% Per IPUC Order 29505)................	-		
96	Oregon - Direct Allocation (100%)....................	-		
97	EEI (1/3 Per IPUC Order 29505).......................	1,380		
98	Total Exclusions......................................	$ 1,840		$ 1,840
99	**Steve Keen**			
100	Total Expenses..	$ 4,455		
101	IDACORP Exclusions Requiring Special Treatment (Listed Below):			
102	Arid Club...	-		
103	EEI...	(2,374)		
104	Oregon Direct Charges...............................	-		
105	Total...	2,081		
106	Payroll Percentage Allocated to IDACORP.............	2.60%		
107	Net IDACORP Exclusions................................	54		
108	Other Exclusions:			
109	Arid Club (100% Per IPUC Order 29505)................	-		
110	Oregon - Direct Allocation (100%)....................	-		
111	EEI (1/3 Per IPUC Order 29505).......................	791		
112	Total Exclusions......................................	$ 845		$ 845
113	**Warren Kline**			
114	Total Expenses..	$ 21,661		
115	IDACORP Exclusions Requiring Special Treatment (Listed Below):			
116	Arid Club...	-		
117	EEI...	-		
118	Oregon Direct Charges...............................	-		
119	Total...	21,661		
120	Payroll Percentage Allocated to IDACORP.............	0.00%		
121	Net IDACORP Exclusions................................	-		
122	Other Exclusions:			
123	Arid Club (100% Per IPUC Order 29505)................	-		
124	Oregon - Direct Allocation (100%)....................	-		
125	EEI (1/3 Per IPUC Order 29505).......................	-		
126	Total Exclusions......................................	$ -		$ -

IDAHO POWER COMPANY
DEDUCTIONS FROM OPERATION AND MAINTENANCE EXPENSES
ADJUSTMENT TO MANAGEMENT EXPENSES
For Twelve Months Ended December 31, 2008

No	Name	(1) Y-T-D Actuals Dec-08	(2) Adjustment	(3) 2008 Base
127	**Luci McDonald**			
128	Total Expenses..	$ 4,685		
129	IDACORP Exclusions Requiring Special Treatment (Listed Below):			
130	Arid Club...	-		
131	EEI...	-		
132	Oregon Direct Charges...............................	-		
133	Total...	4,685		
134	Payroll Percentage Allocated to IDACORP.............	1.50%		
135	Net IDACORP Exclusions................................	70		
136	Other Exclusions:			
137	Arid Club (100% Per IPUC Order 29505)................	-		
138	Oregon - Direct Allocation (100%)....................	-		
139	EEI (1/3 Per IPUC Order 29505).......................	-		
140	Total Exclusions......................................	$ 70		$ 70
141	**Jeffrey Malmen**			
142	Total Expenses..	$ 22		
143	IDACORP Exclusions Requiring Special Treatment (Listed Below):			
144	Arid Club...	-		
145	EEI...	-		
146	Oregon Direct Charges...............................	-		
147	Total...	22		
148	Payroll Percentage Allocated to IDACORP.............	100.00%		
149	Net IDACORP Exclusions................................	22		
150	Other Exclusions:			
151	Arid Club (100% Per IPUC Order 29505)................	-		
152	Oregon - Direct Allocation (100%)....................	-		
153	EEI (1/3 Per IPUC Order 29505).......................	-		
154	Total Exclusions......................................	$ 22		$ 22
155	**James Miller**			
156	Total Expenses..	$ 7,416		
157	IDACORP Exclusions Requiring Special Treatment (Listed Below):			
158	Arid Club...	-		
159	EEI...	-		
160	Oregon Direct Charges...............................	-		
161	Total...	7,416		
162	Payroll Percentage Allocated to IDACORP.............	0.00%		
163	Net IDACORP Exclusions................................	-		
164	Other Exclusions:			
165	Arid Club (100% Per IPUC Order 29505)................	-		
166	Oregon - Direct Allocation (100%)....................	-		
167	EEI (1/3 Per IPUC Order 29505).......................	-		
168	Total Exclusions......................................	$ -		$ -

IDAHO POWER COMPANY
DEDUCTIONS FROM OPERATION AND MAINTENANCE EXPENSES
ADJUSTMENT TO MANAGEMENT EXPENSES
For Twelve Months Ended December 31, 2008

No	Name	(1) Y-T-D Actuals Dec-08	(2) Adjustment	(3) 2008 Base
169	**Dan Minor**			
170	Total Expenses..	$ 18,401		
171	IDACORP Exclusions Requiring Special Treatment (Listed Below):			
172	Arid Club...	-		
173	EEI...	(540)		
174	Oregon Direct Charges...............................	-		
175	Total...	17,861		
176	Payroll Percentage Allocated to IDACORP.............	0.00%		
177	Net IDACORP Exclusions................................	-		
178	Other Exclusions:			
179	Arid Club (100% Per IPUC Order 29505)................	-		
180	Oregon - Direct Allocation (100%)....................	-		
181	EEI (1/3 Per IPUC Order 29505).......................	180		
182	Total Exclusions......................................	$ 180		$ 180
183	**Greg Panter**			
184	Total Expenses..	$ 3		
185	IDACORP Exclusions Requiring Special Treatment (Listed Below):			
186	Arid Club...	-		
187	EEI...	-		
188	Oregon Direct Charges...............................	-		
189	Total...	3		
190	Payroll Percentage Allocated to IDACORP.............	100.00%		
191	Net IDACORP Exclusions................................	3		
192	Other Exclusions:			
193	Arid Club (100% Per IPUC Order 29505)................	-		
194	Oregon - Direct Allocation (100%)....................	-		
195	EEI (1/3 Per IPUC Order 29505).......................	-		
196	Total Exclusions......................................	$ 3		$ 3
197	**Thomas Saldin**			
198	Total Expenses..	$ 2,214		
199	IDACORP Exclusions Requiring Special Treatment (Listed Below):			
200	Arid Club...	-		
201	EEI...	-		
202	Oregon Direct Charges...............................	-		
203	Total...	2,214		
204	Payroll Percentage Allocated to IDACORP.............	4.40%		
205	Net IDACORP Exclusions................................	97		
206	Other Exclusions:			
207	Arid Club (100% Per IPUC Order 29505)................	-		
208	Oregon - Direct Allocation (100%)....................	-		
209	EEI (1/3 Per IPUC Order 29505).......................	-		
210	Total Exclusions......................................	$ 97		$ 97

IDAHO POWER COMPANY
DEDUCTIONS FROM OPERATION AND MAINTENANCE EXPENSES
ADJUSTMENT TO MANAGEMENT EXPENSES
For Twelve Months Ended December 31, 2008

No	Name	(1) Y-T-D Actuals Dec-08	(2) Adjustment	(3) 2008 Base
211	**Lori Smith**			
212	Total Expenses..	$ 12,009		
213	IDACORP Exclusions Requiring Special Treatment (Listed Below):			
214	Arid Club...	-		
215	EEI...	(2,377)		
216	Oregon Direct Charges...............................	-		
217	Total...	9,632		
218	Payroll Percentage Allocated to IDACORP.............	4.60%		
219	Net IDACORP Exclusions.................................	443		
220	Other Exclusions:			
221	Arid Club (100% Per IPUC Order 29505)................	-		
222	Oregon - Direct Allocation (100%)....................	-		
223	EEI (1/3 Per IPUC Order 29505).......................	792		
224	Total Exclusions.......................................	$ 1,235		$ 1,235
225	Total Reduction to Officer's Expenses................	$ 8,636	$ -	$ 8,636

IDAHO POWER COMPANY
DEDUCTIONS FROM OPERATION AND MAINTENANCE EXPENSES
OTHER EXCLUSIONS
For Twelve Months Ended December 31, 2008

	Account	(1) Y-T-D Actuals Dec 2008	(2) Adjustment	(3) 2008 Base
1	500	$ 21		$ 21
2	535	200		200
3	536	251		251
4	537	1,153		1,153
5	539	393		393
6	541	12		12
7	542	43		43
8	544	29		29
9	545	56		56
10	553	55		55
11	557	1,282		1,282
12	560	326		326
13	561	36		36
14	562	126		126
15	563	222		222
16	566	8		8
17	568	197		197
18	570	229		229
19	571	311		311
20	580	1,627		1,627
21	581	51		51
22	582	326		326
23	583	788		788
24	584	408		408
25	586	44		44
26	587	111		111
27	588	1,116		1,116
28	592	1,657		1,657
29	593	655		655
30	594	136		136
31	596	50		50
32	597	125		125
33	598	89		89
34	901	84		84
35	902	163		163
36	907	247		247
37	908	1,018		1,018
38	910	275		275
39	921	5,664		5,664
40	923	-		-
41	926	2,852		2,852
42	930	170		170
43	935	183		183
44	Total	$ 22,789	$ -	$ 22,789

Idaho Power/403
Witness: Douglas N. Jones

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Douglas N. Jones
Additional Ratebase and Expense Adjustments for 2008

July 31, 2009

Idaho Power Company
Before The Oregon Public Utilities Commission
Additional Ratebase and Expense Adjustments for 2008

Line No.	Description	(1) Account No.	(2) 2008 Ratebase	(3) 2008 Revenue	(4) 2008 Expense	
1	Prairie Acquisition Adjustment (IPUC Order No. 29505)	114	$ (454,449)			
2		115	373,026			
3			$ (81,423)			
4	IERCO Rate Base Adjustment (Bridger Used and Useful Adjustment - IPUC Order No. 29505)	123	$ (85,531)			
5	Energy Efficiency Rider (IPUC Order No. 30189)	456		$ (18,880,276)		
6	Energy Efficiency Rider (IPUC Order No. 30189)	908			$ (18,880,276)	
7	Incentive (To Remove 2008 Actuals)	920			$ (15,448,509)	
8	Intervenor Funding-Idaho Irrigators (IPUC Order No. 30035)	928			$ (31,378)	(1)
9	Intervenor Funding-NW Energy Coalition (IPUC Order No. 30215)	928			$ (6,091)	(1)
10	Intervenor Funding-NW Energy Coalition (IPUC Order No. 30267)	928			$ (7,500)	(1)

(1) Removed residual 2008 amortization since it was included in the 2007 revenue requirement.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE _______

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE IN THE STATE OF OREGON.	))))))

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

CATHERINE M. MILLER

July 31, 2009

Q. Please state your name and business address.

A. My name is Catherine M. Miller. 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 "Company") as Director of Strategic Analysis.

Q. Please describe your educational background.

A. I graduated in 1991 from Idaho State University, Pocatello, Idaho, receiving a Bachelor of Business Administration degree in Accounting. In 1998, I received a Master of Business Administration degree from Boise State University in Boise, Idaho. I have attended numerous seminars and conferences on accounting, management, and finance issues related to the utility industry. I have been a Certified Public Accountant licensed in the state of Idaho since 1992.

Q. Please describe your business experience with Idaho Power.

A. In 1991, I began my association with Idaho Power as external auditor for Deloitte & Touche, LLP, the Company's external audit firm. I joined Idaho Power in May of 1994 as a Tax Analyst in the Tax Department where I was responsible for preparing monthly tax accruals, tax forecasts, tax returns, and tax analyses. In August of 1996, I was promoted to a Business Analyst in the Financial Research and Support Department. My duties as a Business Analyst included the preparation of the Company's financial forecasts and the preparation of a wide range of financial and regulatory analyses. In February of 2001, I was promoted to Finance Team Leader III for the Strategic Analysis Department. In that capacity, I became responsible for overall financial support, financial forecast activities, and non-regulated subsidiary accounting. Non-regulated subsidiary accounting was eventually transferred out of the Strategic Analysis Department.

In 2004, I was promoted to my current position of Director of Strategic Analysis in the Corporate Planning and Risk Management Department. I currently supervise two departments, Strategic Analysis and Regulatory Accounting and Support. Strategic Analysis prepares the Company's consolidated financial forecasts, provides updates to management, and prepares a wide range of financial analyses as requested. Regulatory Accounting and Support is responsible for all regulatory accounting and coordinates Finance Department support of regulatory filings.

Q. Could you briefly summarize how the Company has developed its 2009 test year ("2009 Test Year" or "Test Year")?

A. Yes. The development of the 2009 Test Year began with 2008 actual financial data ("2008 Actuals"). 2008 Actuals were adjusted by Company witness Douglas Jones to reflect traditional ratemaking adjustments and to arrive at 2008 adjusted actual financial information ("2008 Base"). The 2008 Base was then adjusted to reach 2009 forecasted financial levels ("2009 Unadjusted Forecast Year"). Finally, traditional and other ratemaking adjustments were made to the 2009 Unadjusted Forecast Year to reach the Company's 2009 Test Year.

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

A. The purpose of my testimony is to present the forecast methodologies that were applied to the 2008 Base Year to arrive at the 2009 Unadjusted Forecast Year. I will then present the traditional and other ratemaking adjustments made to the 2009 Unadjusted Forecast Year to reach the Company's proposed 2009 Test Year.

Q. Will you be providing testimony regarding any of the normalizing adjustments to the 2009 Test Year?

A. No. Company witness Jeannette Bowman will address the normalizing adjustments to sales and revenues. Company witness Scott Wright will testify to the normalization of power supply costs, which has already been discussed to some degree by Company witness Gregory Said.

Q. Please describe the forecast methodologies used to adjust the 2008 Base Year to the 2009 Unadjusted Forecast Year.

A. There are three primary methods that were developed and applied to forecast the 2009 Unadjusted Forecast Year from the 2008 Base Year: (1) Compound Annual Growth Rates ("CAGRs"), (2) Fixed and Other Adjustments based upon known information or when information is more reflective of current circumstances, and (3) the continued use of 2008 actual financial data without change.

Q. Please describe the nature of accounts for which forecast method 1, the CAGR, is appropriate.

A. The purpose of a CAGR is to determine the historical trend for growth over a specific period of time.

Q. What is the benefit of using a CAGR in forecasting future revenues and expenses?

A. The CAGR represents the compounded average growth rate over a number of periods. It smoothes out uneven amounts between periods and represents a steady level of positive or negative growth from the beginning period to the ending period. Thus, using the CAGR, volatility created by unusual, intermittent, or non-recurring events recorded in a particular period can be eliminated.

Q. Please describe the nature of accounts for which using forecast method 2, use of known information or information more reflective of current circumstances, is appropriate.

In certain cases, the utility has specific knowledge regarding expenditures that will be incurred or revenues that will be received in an account such that this knowledge must be incorporated in order to more accurately estimate 2009 revenues and spending levels. For this reason, when information more reflective of current circumstances was available, such as changes in contracts or the addition or deletion of customers, the Company reflected that knowledge in its forecasts. As an example, let me describe how the real and personal property tax forecast was developed. The Company's property taxes are not amenable to the CAGR method due to tax anomalies in Idaho in 2007. Therefore, the methodology used to project 2009 property taxes is the same used for establishing the 2009 property tax accrual used for the Company's financial statements. Further discussion of the forecast for Taxes Other than Income Taxes can be found in the Forecast Methodology Manual (Exhibit No. 506) which will be discussed later in my testimony.

Q. Please describe the nature of accounts for which using forecast method 3, 2008 actual financial amounts, as the forecast for the 2009 Unadjusted Forecast Year is appropriate.

A. There are certain accounts that, by their nature, do not increase over time or for which it would be reasonable to forecast that they will remain at 2008 levels through the duration of the 2009 Test Year. For these accounts, the Company used 2008 Actuals.

Q. Are there other instances where the Company kept expenditures at 2008 levels.

A. Yes. In certain cases, where the account balances were small, the Company used 2008 Actuals. An example is other revenue from transformer and distribution rentals (Account 454), which was $17,330 in 2008. This actual 2008 amount was carried forward as the forecast for 2009.

Q. Has Idaho Power used these forecast methods in other regulatory proceedings?

A. Yes. As Mr. Said has previously testified, since the last Oregon general rate case, the Company presented forecasted test years twice in Idaho. The methods I propose in this case were used to prepare the Company's 2008 Idaho rate case.

Q. Have you prepared an exhibit that lists all accounts and identifies the specific method you used to forecast the 2009 Unadjusted Forecast Year?

A. Yes. I directed the preparation of Exhibit No. 505 to present a summarized list of all accounts to which the three previously discussed methods were applied. Each of the methodologies is described in more detail within the Forecast Methodology Manual, Exhibit No. 506. To develop the Forecast Methodology Manual, the Company performed a review of each group of accounts included within the test year and based upon specific knowledge and analysis of that account grouping, either used 2008 Actuals or applied another methodology to that account that represents the most appropriate level of anticipated spending.

Q. Have you prepared an exhibit that provides a detailed description of the methods by account used to forecast the 2009 Unadjusted Forecast Year?

A. Yes. I directed the preparation of the Forecast Methodology Manual, Exhibit No. 506, which provides a detailed description of the methodologies used to adjust the 2008 Base Year to the 2009 Unadjusted Forecast Year.

Q. Have the data and the associated adjustments made to your exhibits and supporting schedules been calculated on a total system basis?

A. Yes.

Q. Please provide an overview of the methodologies included in the Forecast Methodology Manual (Exhibit No. 506).

A. The answer to this question is rather lengthy. I will provide an overview for the methodology used for each of the major areas and segment my response to address Other Operating Revenues (Accounts 451, 454, and 456), Operation and Maintenance ("O&M") expense (Accounts 500 through 900), Depreciation and Amortization Expense (Accounts 403 and 404), and Electric Plant in Service ("EPIS") (Account 101). More detailed discussion of the accounts and methods used is provided in Exhibit No. 506.

Q. Please provide an overview of the methodology used to forecast 2009 Other Operating Revenues (Accounts 451, 454, and 456).

A. Revenues for substation equipment, transformer and distribution rentals, station and line rentals, photovoltaic revenues, Antelope substation rentals, Sierra Pacific Power company sales, stand-by service, and other miscellaneous items were forecasted to be the same as 2008 actual revenue. A 2006-2008 CAGR was used to project miscellaneous service revenue, cogeneration and small power production revenues, and various rental revenues. Information more reflective of current circumstances was used to project Network services and other Long Term Firm and point-to-point transmission revenue.

Q. Please provide an overview of the methodology used to forecast 2009 Operation and Maintenance Expense (Accounts 500 through 900).

A. Fuel Expense (Accounts 501 and 547) and Purchased Power Expense (Account 555) were normalized and are discussed by both Mr. Wright and Mr. Said. Water for Power Expense (Account 536) and Transmission of Electricity by Others (Account 565) were projected to remain at 2008 levels. Uncollectible Accounts Expense (Account 904) and Property Insurance Expense (Account 924) incorporated known factors reflecting current economic conditions. The Idaho Energy Efficiency Rider (Account 908) was removed in its entirety from the 2009 Test Year. The remaining O&M expense amounts were segregated into labor and non-labor expense groupings.

Q. Please provide an overview of the methodology used to forecast 2009 O&M labor expense.

A. The historical 2004-2008 CAGR for gross labor expense is 6.85 percent. This CAGR was applied to actual 2008 gross labor expense in determining 2009 Unadjusted Forecast Year levels. This growth rate reflects merit salary increases, the salary structure adjustments, and increased employee levels. Because a portion of labor is capitalized, the 2008 actual percentage of O&M labor expense to gross labor was applied to produce 2009

Unadjusted Forecast Year O&M straight time labor expense. Then the 2008 actual loading percentage reflecting health care and other benefits was applied and actual 2008 overtime and other payroll expense amounts were included. As a result, 2009 Unadjusted Forecast Year O&M labor expense increased 6.56 percent over comparable 2008 actual amounts. The 2009 Unadjusted Forecast Year O&M labor amount was then allocated to O&M FERC account based on 2008 actual amounts.

Q. Please provide an overview of the forecast methodology used to forecast 2009 non-labor O&M expense.

A. For non-labor expense, excluding the accounts mentioned above, the weighted average 2004-2008 CAGR is 6.75 percent. Although Idaho Power considers the 2004-2008 CAGR to be the most appropriate method for estimating anticipated non-labor spending as it reflects growth, inflation, and smoothes unusual events, given the current economic downturn and the impact of the recent extended drought, the Company has responded by finding areas of spending that can be deferred or eliminated.

Actual 2008 non-labor O&M, excluding the items identified previously, equaled $146.3 million. Had the 2004-2008 CAGR been incorporated in this rate case, non-labor O&M would have been projected to increase $9.9 million to $156.2 million. As mentioned previously, this level of growth over 2008 actual levels was determined to be unreasonable given current conditions and senior management, rather than including an increase of $9.9 million, has lowered the targeted level of spending in some cases to below 2008 actual levels. For Hydraulic Power Generation (Accounts 535-545) and Other Power Generation (Accounts 546-557), non-labor spending has been held at 2008 levels with a estimated additional expense of $1.2 million for a scheduled hot gas path inspection and resulting costs for the Evander Andrews Complex – CT2. Steam Power Generation (Accounts 500-514) was grown at the 2004-2008 CAGR of 3.66 percent or $1.6 million for its account grouping. Regarding the remaining functional groupings, the Company has initiated expense reductions in the areas of purchased services, materials, transportation, software maintenance, travel and training. As a result, Transmission Expenses (Accounts 560-573) were lowered $0.9 million, Distribution Expenses (Accounts 580-598) were lowered $4.2 million, Customer Accounting and Services and Information Expenses were increased $0.4 million, and Administration and General Expense were lowered $3.0 million. The total reduction from 2008 actual non-labor expense equals $4.9 million resulting in $141.4 million being included in the 2009 Unadjusted Forecast Year for non-labor O&M.

Q. Please provide an overview of the methodology to forecast 2009 Depreciation and Amortization Expense (Accounts 403 and 404).

A. The 2009 depreciation expense, amortization expense, and related reserve accounts were calculated based on the monthly estimated 2009 plant balances (see Electric Plant in Service Account 101 for discussion). Depreciation rates authorized by the Idaho Public Utilities Commission ("IPUC") Order No. 30639 were used for the entire 2009 Test Year. Parties to the Company's Oregon Public Utilitiy Commission ("OPUC") depreciation filing (Docket No. UM 1395) have filed a Stipulation Agreement in support of these rates, although an order has not yet been issued.

Q. Please provide an overview of the methodology to forecast 2009 Electric Plant in Service (Account 101).

A. EPIS is a function of multiple components, including actual year-end 2008 EPIS and Construction Work in Progress ("CWIP") balances, estimated 2009 spending, expected 2009 closings of CWIP, and estimated retirements. Therefore, it was necessary to use a number of methodologies to develop the 2009 Unadjusted Forecast Year EPIS balances.

To project 2009 construction expenditures ("Construction") and 2009 closings of CWIP to EPIS, at Mr. Said's instruction, the Company first bifurcated into two separate and distinct parts those projects in excess of $2 million and those under $2 million. This separation is explained more fully in the Forecast Methodology Manual (Exhibit No. 506).

Projects in excess of $2 million were reviewed by the individual project managers, who estimated the costs to complete and the in-service date of each project. After analyzing the under $2 million projects (excluding vehicles) closing to EPIS as a group, it was determined that an application of a historical growth rate would not be appropriate given the current economic environment. Therefore, for projects less than $2 million, 2009 closings were forecasted to be comparable to actual 2008 closings to EPIS when determining the 2009 Unadjusted Forecast Year.

ANNUALIZING & OTHER ADJUSTMENTS TO ARRIVE AT THE 2009 TEST YEAR

Q. In Mr. Jones's testimony, he described the various adjustments that were made to 2008 Actuals to arrive at the 2008 Base Year. Do these same adjustments need to be made in 2009?

A. No. These adjustments are standard ratemaking adjustments based on prior Commission orders and are adjustments to charges included in the 2008 Actuals. By removing them from 2008 Actuals prior to applying the various methodologies to arrive at the Company's proposed 2009 Unadjusted Forecast Year, the same adjustments are already accounted for.

Q. Are there any additional adjustments that need to be made to properly reflect the 2009 Test Year?

A. Yes. It is necessary for the Company to make additional annualizing and known and measureable adjustments.

Q. Please describe the additional annualizing adjustments made under your direction to the 2009 Test Year.

A. Under my direction, annualizing adjustments were made to certain expense and rate base items to reflect them as though they have been in existence for the entire Test Year, or at year-end 2009 levels. These include year-end payroll, incentive pay, the year-beginning 2010 salary structure adjustment, depreciation expense and reserve, and plant placed in service during 2009 in excess of $2 million with the associated property taxes and insurance. Such adjustments are appropriate to reflect conditions that will be in effect at the time rates are placed in effect.

Q. Please summarize the annualizing and other regulatory adjustments made under your supervision for the 2009 Test Year.

A. The traditional regulatory annualizing adjustments for the 2009 Test Year in Exhibit Nos. 501-503 were made under my supervision. These adjustments reflect changes to certain expense and rate base items to treat them as though they have been in existence for a full year or to year-end 2009 levels, whichever is applicable. These include the operating expense adjustments for: (1) a payroll annualizing increase of $3,104,828 (Exhibit No. 501), (2) the inclusion of the 2009 normalized incentive target of $6,776,573 (Exhibit No. 501), (3) the annualized accumulated reserve adjustment of $1,309,324 and depreciation expense adjustment of $2,592,443 on Exhibit No. 502, and (4) the 2009 major plant additions annualizing adjustment of $18,568,593 with the associated property tax adjustment of $72,575 and insurance expense of $7,929 on Exhibit No. 503.

Q. Please describe in more detail why an annualizing adjustment of $3,104,828 is necessary for payroll expense.

A. Payroll expense included in the 2009 Unadjusted Forecast Year O&M expense was developed using a 2004-2008 CAGR that was applied to 2008 labor expense. Through an individual year, monthly labor expense grows over the year due to new hires and merit salary increases resulting in higher December payroll expense that would continue into the following year. Therefore, to fully reflect labor expense at the time rates go into effect, the 2009 Test Year must be adjusted to include payroll expense levels at the end of the 2009 Unadjusted Forecast Year. Exhibit No. 501, page 2, presents the calculation of the payroll annualizing adjustment which is based on forecasted December 2009 payroll expense.

Q. Please summarize the known and measurable adjustments for the 2009 Test Year made under your supervision.

A. Under my supervision, traditional regulatory known and measurable adjustments were made to the 2009 Test Year as shown in Exhibit No. 504, pages 1 through 3. This exhibit reflects certain known and measurable adjustments to expenses and rate base that will occur subsequent to year-end 2009. Pages 1 and 2 of Exhibit No. 504 reflect the normalized annual salary structure adjustment of $3,692,594 and the detailed calculation of this number. Page 3, line 1 of Exhibit 504 reflects an adjustment of $2,442 to increase rate base for interest calculated from January 1 through May 31, 2010, on the deferred balance of the Oregon portion of the Grid West Loans deferred as a result of OPUC Order No. 06-483. Page 3, line 2 of Exhibit No. 504 reflects an increase in expense of $14,439 for one full year of amortization of the deferred balance at May 31, 2009, based on a five-year amortization period.

Q. Please explain the rational for the known and measurable adjustments for the Grid West Loans deferral on page 3 of Exhibit No. 504.

A. OPUC Order 06-483 authorized the Company to defer with interest the Oregon portion of costs associated with the loans provided to Grid West. This order also allowed for future ratemaking treatment to recover and amortize these costs. Therefore, the Company has accrued interest up until the point at which rates would go into effect as a result of this filing and has increased expense for one year of amortization based on an assumed five-year amortization period. The assumed amortization period is consistent with previously received IPUC Order No. 30157 and Federal Energy Regulatory Commission ("FERC") Docket No. ER-08-629.

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

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Catherine M. Miller
Annualized Operating Payroll and Incentive Expense Adjustments

July 31, 2009

Idaho Power Company
Annualized Operating Payroll
and Incentive Expense Adjustments

Line No.		Amount
1	Operating Payroll - Annualizing Adjustment	$ 3,104,828
2	Normalized Incentive	6,776,573
3	**Total Adjustments**	$9,881,400

Idaho Power Company
Annualized Operating Payroll
and Incentive Expense Adjustments

Line No.			Amount
	1) Operating Payroll (Various accts)		
1	Forecasted December 2009 ST Payroll		11,821,483
2	Annualized December 2009(Dec times 13)		153,679,279
3	O&M Percentage		55.58%
4	Annualized O&M Wages Subject to Benefit Loading		85,410,683
5	Benefit Loading Percent		44.11%
6	Annualized Loaded Wages		123,086,461
7	Loaded 2009 O&M Wage Forecast		(119,981,634)
8	Adjustment to Operating Expense		$ 3,104,828
	2) Incentive Expense (920 account))		
9	Annualized December 2009 ST Payroll		$ 153,679,279
10	Plus: 2008 Overtime Payroll		7,603,204
11	Less:2008 Officer Payroll	(3,693,832)	
12	Times Annualized Payroll Growth Factor	6.85%	(3,946,967)
13	Total Payroll Excl Officers		157,335,516
14	Normalized Incentive Rate		4.00%
15	Normalized Incentive		6,293,421
16	Payroll Tax on Normalized Incentive @	9.11%	573,049
17	Normalized Incentive Including Payroll Tax		6,866,470
18	Times incentive operating percent		98.69%
19	Adjustment to Operating Expense for Incentive		$ 6,776,573

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Catherine M. Miller
Annualizing Adjustments for Amortization and Depreciation Expense
and Accumulated Reserve

July 31, 2009

Idaho Power Company
Annualizing Adjustments for Amortization and Depreciation Expense and Accumulated Reserve

Account	Account Description	Annualized Amortization & Depreciation Expense	Forecasted Amortization & Depreciation Expense	Annualizing Adjustment	Reserve Adjustment
301	Organization				
302	Franchises and Consents	781,063.44	781,063.44	-	-
303	Miscellaneous Intangible Plant	5,496,904.68	5,492,801.16	4,103.52	2,051.76
TOTAL	**INTANGIBLE PLANT**	6,277,968.12	6,273,864.60	4,103.52	2,051.76
310	Land and Land Rights	3,215.76	3,215.76	-	-
311	Structures and Improvements	2,072,328.48	2,068,938.16	3,390.32	1,695.16
312	Boiler Plant Equipment	11,369,915.52	11,280,433.18	89,482.34	44,741.17
314	Turbogenerator Units	3,419,069.28	3,385,190.27	33,879.01	16,939.50
315	Accessory electric Equipment	842,733.24	842,833.77	(100.53)	(50.27)
316	Misc Power Plant Equipment	532,896.36	532,130.03	766.33	383.17
TOTAL	**STEAM PRODUCTION PLANT**	18,240,158.64	18,112,741.17	127,417.47	63,708.73
330	Land and Land Rights			-	-
331	Structures and Improvements	4,048,125.24	3,991,553.88	56,571.36	28,285.68
332	Reservoirs, Dams, Waterways	5,638,720.68	5,618,285.68	20,435.00	10,217.50
333	Waterwheel, Turbines, Generato	3,603,252.36	3,587,056.97	16,195.39	8,097.69
334	Accessory Electric Equipment	1,286,631.72	1,266,425.87	20,205.85	10,102.92
335	Misc Power Plant Equipment	495,940.80	476,586.71	19,354.09	9,677.04
336	Roads, Railroads and Bridges	144,758.64	144,758.64	-	-
TOTAL	**HYDRO PRODUCTION PLANT**	15,217,429.44	15,084,667.75	132,761.69	66,380.83
340	LAND AND LAND RIGHTS				
341	Structures and Improvements	321,318.48	320,893.02	425.46	212.73
342	Fuel Holders, Producers, Acces	145,868.28	145,623.81	244.47	122.24
343	Prime Movers	2,965,609.56	2,961,065.18	4,544.38	2,272.19
344	Generators	1,082,610.24	1,081,073.00	1,537.24	768.62
345	Accessory Electric Equipment	557,161.80	556,134.20	1,027.60	513.80
346	Misc Power Plant Equipment	91,647.84	91,505.72	142.12	71.06
TOTAL	**OTHER PRODUCTION PLANT**	5,164,216.20	5,156,294.93	7,921.27	3,960.64
350	Land and Land Rights	353,671.80	353,671.80 *	0.00	-
352	Structures and Improvements	743,842.92	722,072.57	21,770.35	10,885.18
353	Station Equipment	6,298,048.80	6,130,985.74	167,063.06	83,531.53
354	Towers and Fixtures	2,823,309.60	2,742,659.79	80,649.81	40,324.90
355	Poles and Fixtures	2,669,967.48	2,638,395.16	31,572.32	15,786.16
356	Overhead Conductors, Devices	2,968,313.76	2,923,034.72	45,279.04	22,639.52
359	Roads and Trails	3,132.60	3,132.60	-	-
TOTAL	**TRANSMISSION PLANT**	15,860,286.96	15,513,952.38	346,334.58	173,167.29
360	Land and Land Rights				
361	Structures and improvements	510,572.16	475,531.76	35,040.40	17,520.20
362	Station Equipment	3,402,374.40	3,261,201.40	141,173.00	70,586.50
TOTAL	**SUBSTATION EQUIPMENT**	3,912,946.56	3,736,733.16	176,213.40	88,106.70
364	Poles, Towers and Fixtures	7,254,427.08	7,072,734.75	181,692.33	90,846.16
365	Overhead Conductors, Devices	3,612,818.76	3,521,191.79	91,626.97	45,813.48
366	Underground Conduit	958,382.64	942,257.48	16,125.16	8,062.58
367	Underground Conductors, Device	3,664,736.04	3,596,817.25	67,918.79	33,959.40
368	Line Transformers	6,513,444.96	6,435,391.73	78,053.23	39,026.61
369	Services	1,748,233.08	1,733,638.61	14,594.47	7,297.23
370	Meters	5,779,741.68	5,253,926.33	525,815.35	262,907.68
371	Installations, Cust Premises	27,055.08	26,796.50	258.58	129.29
373	Street Lighting, Signal System	171,497.64	170,861.18	636.46	318.23
TOTAL	**DISTRIBUTION LINES**	29,730,336.96	28,753,615.62	976,721.34	488,360.66
389	Land and Land Rights				
390	Structures and Improvements	1,816,309.20	1,770,637.34	45,671.86	22,835.93
391	Office Furniture, Equipment	9,464,728.56	8,882,189.29	582,539.27	291,269.64
392	Transportation Equipment	2,144,928.72	2,139,023.05		3,097.09
393	Stores Equipment	68,597.04	65,551.53	3,045.51	1,522.76
394	Tools, Shop, Garage Equipment	249,426.60	241,512.26	7,914.34	3,957.17
395	Laboratory Equipment	628,255.80	605,161.52	23,094.28	11,547.14
396	Power Operated Equipment	638,730.48	618,685.05		10,005.41
397	Communication Equipment	2,124,044.88	1,997,258.44	126,786.44	63,393.22
398	Miscellaneous Equipment	470,130.96	438,212.60	31,918.36	15,959.18
TOTAL	**GENERAL EQUIPMENT PLANT**	17,605,152.24	16,758,231.08	820,970.06	423,587.54
TOTAL ELECTRIC PLANT IN SERVICE		112,008,495.12	109,390,100.68	2,592,443.34	1,309,324.15
	Amortization of Disallowed Costs	(296,299.32)	(296,299.32)	-	-
TOTAL DEPRECIATION & AMORTIZATION		111,712,195.80	109,093,801.36	2,592,443.34	1,309,324.15

Idaho Power/503
Witness: Catherine M. Miller

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Catherine M. Miller
Major Plant Additions Annualized for 2009

July 31, 2009

Idaho Power Company
Major Plant Additions Annualized for 2009

Line No.	Project Type	Project ID	Description	(1) In Service Date	(2) Annualized Plant	(3) Adjustment for Plant Est to Close 2009	(4) Net Annualizing Adjustments	(5) Annual Composite Property Tax Rate	(6) Annual Composite Property Tax	(7) Annual Insurance Rate Per $100	(8) Annual Insurance Expense
	Transmission										
	Stations:										
1	32	BMPR0601	Danskin Additional Peaker - NUG	March, 2009	170	131	39				
2		BORA0803	Populus Upgrades	April, 2009	3,358,031	2,324,791	1,033,240				
3		DNPR0701	Danskin Additional Peaker - NUG	March, 2009	1	1	0				
4		DNPR0702	Elmore County Upgrades	March, 2009	4,824,587	3,711,221	1,113,366				
5		HBRD0601	Danskin Additional Peaker - NUG	April, 2009	4,797,321	3,321,222	1,476,099				
6	32 Total				12,980,110	9,357,365	3,622,745	0.370%	13,404	$ 0.0427	1,547
	Lines:										
7	33	T7110701	Danskin Additional Peaker - NUG	March, 2009	315,520	242,708	72,812				
8		T7230601	Danskin Additional Peaker - NUG	March, 2009	280,750	215,962	64,788				
9		T7240601	Danskin Additional Peaker - NUG	March, 2009	(1,192)	(917)	(275)				
12		T9190501	Elmore County Upgrades	March, 2009	142,631	109,716	32,915				
13		T9510703	Replace Facilities - Midpoint - Borah #2	June, 2009	2,355,689	1,268,448	1,087,241				
14	33 Total				3,093,398	1,835,916	1,257,482	0.370%	4,653	$ 0.0427	537
	Distribution										
	Underground Lines:										
15	40	UGCI0301	URD Cable replacements and maint.	March, 2009	44,126	33,943	10,183				
16		UGCI0401	URD Cable replacements and maint.	December, 2009	1,703,535	131,041	1,572,494				
17		UGCR0401	URD Cable replacements and maint.	December, 2009	2,476,551	190,504	2,286,047				
18	40 Total				4,224,212	355,488	3,868,724	0.420%	16,249	$ 0.0427	1,652
	Substations:										
19	41	HAVN0603	Eastern Area 46/138kV Conversion	July, 2009	2,781,700	1,283,862	1,497,838				
20		HYDA0801	Add T132 and HYDA-044 for Jerome Urban Renewa	July, 2009	2,243,998	1,035,691	1,208,307				
21	41 Total				5,025,698	2,319,553	2,706,145	0.420%	11,366	$ 0.0427	1,156
	Overhead Lines:										
22	43	ELMR0701	Danskin Additional Peaker - NUG	March, 2009	43,291	33,301	9,990				
23		MORA0701	Danskin Additional Peaker - NUG	March, 2009	451,060	346,969	104,091				
24	43 Total				494,351	380,270	114,081	0.420%	479	$ 0.0427	49
	Communication Equipment:										
25	62	BMPR0602	Danskin Additional Peaker - NUG	March, 2009	70,397	54,152	16,245				
26		CDAL0605	Danskin Additional Peaker - NUG	March, 2009	62,354	47,965	14,389				
27		CDDC0601	Danskin Additional Peaker - NUG	March, 2009	2,468	1,898	570				
28		DNPR0602	Danskin Additional Peaker - NUG	March, 2009	119,534	91,949	27,585				
29		ELMR0601	Elmore County Upgrades	March, 2009	29,903	23,002	6,901				
30		MHMW0602	Danskin Additional Peaker - NUG	March, 2009	10,281	7,908	2,373				
31		MORA0602	Danskin Additional Peaker - NUG	March, 2009	140,422	108,017	32,405				
32		RTSN0601	Elmore County Upgrades	March, 2009	30,102	23,155	6,947				
33		T4380603	Danskin Additional Peaker - NUG	March, 2009	159,552	122,732	36,820				
34		T7230701	Elmore County Upgrades	March, 2009	86,323	66,402	19,921				
35	62 Total				711,336	547,182	164,154	0.420%	689	$ 0.0427	70
	Total Transmission and Distribution				26,529,105	14,795,774	11,733,331		46,840		5,010
	Power Supply:										
	Thermal:										
36	21	B00809252	Unit 2 SO2 Upgrades	July, 2009	5,399,009	2,491,850	2,907,159				
37		B00809252	Unit 2 SO2 Upgrades	August, 2009	1,015,048	390,403	624,645				
38		B00809252	Unit 2 SO2 Upgrades	September, 2009	333,350	102,569	230,781				
39		B00809252	Unit 2 SO2 Upgrades	October, 2009	350,018	80,773	269,245				
40		B00809260	Unit 2 Reheater Outlet Terminal Tubes (27284	June, 2008	1,979,524	1,065,898	913,626				
41		B00809260	Unit 2 Reheater Outlet Terminal Tubes (27284	July, 2008	44,642	20,604	24,038				
42		B00708267	Valmy 36892 Spare GSU Transformer (27301410)	March, 2009	2,154,000	1,656,923	497,077				
43	21 Total				11,275,591	5,809,021	5,466,570	0.370%	20,226	$ 0.0427	2,334
	Hydro:										
44	23	TBD	Purchase Water Right	March, 2009	2,081,000	1,600,769	480,231				
45	23 Total				2,081,000	1,600,769	480,231	0.370%	1,777	$ 0.0427	205
46	**Total Power Supply**				13,356,591	7,409,790	5,946,801		22,003		2,539
	Corporate Administration Support:										
	General Land and Buildings:										
47	51	51 B00700209	McCall Op Cntr - Building	March, 2009	3,850,000	2,961,538	888,462				
48	51 Total				3,850,000	2,961,538	888,462	0.420%	3,732	$ 0.0427	379
49	**Total Corporate Administration Support**				3,850,000	2,961,538	888,462		3,732		379
50	**Total**				$ 43,735,696	$ 25,167,103	$ 18,568,593		$ 72,575		$ 7,929

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Catherine M. Miller
Known and Measurable Adjustments
(Salary Structure Adjustment and Grid West Loan)

July 31, 2009

Idaho Power Company
Known and Measurable Adjustment to 2009
Operating Expense (Salary Structure Adjustment)

Line No.		Amount
1	2010 Salary Structure Adjustment	$ 3,692,594
2	**Total Adjustments**	$3,692,594

Idaho Power Company
Known and Measurable Adjustment to 2009
Operating Expense (Salary Structure Adjustment)

Line No.			Amount
	1) Operating Payroll (Various accts)		
1	Forecasted December 2009 ST Payroll		11,821,483
2	Annualized December 2009(Dec times 13)		153,679,279
	3) 2010 Operating Payroll SSA (Various accts)		
3	Annualized December 2009		$ 153,679,279
4	2010 Structured Salary Adjustment	3.00%	4,610,378
5	O&M Percentage		55.58%
6	O&M Wages Subject to Benefit Loading		2,562,320
7	Benefit Loading Percent		44.11%
8	Adjustment to Operating Expense		$ 3,692,594

Idaho Power Company
Before The Oregon Public Utilities Commission
Known and Measurable Adjustment to 2009
Operating Expense (Salary Structure Ajustment)
Grid West Loan

Line No.	Description	(1) Account No.	(2) 2010 Ratebase	(3) 2010 Revenue	(4) 2010 Expense
1	Oregon Grid West (OPUC Order No. 06-483)	182	$ 2,442		
2	Oregon Grid West (OPUC Order No. 06-483)	566			$ 14,439

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Catherine M. Miller
Forecast Methodology Summary

July 31, 2009

IDAHO POWER COMPANY
Forecast Methodology Summary
2009 Test Year

LINE NO	Description	(1) FERC ACCOUNT NUMBER	(2) Methodology	(3) Growth Percentage
	Cost of Service Components			
	Other Operating Revenues			
1	Miscellaneous Service Revenues	451	2006-2008 CAGR	-17.75%
	Rent from Electric Property			
2	Substation equipment	454	2008 Actual	
3	Transformer & distribution rentals	454	2008 Actual	
4	Station and line rentals	454	2008 Actual	
5	Cogeneration and small power production	454	2006-2008 CAGR	4.66%
6	Real estate rents	454	2006-2008 CAGR	3.07%
7	Dark fiber rents	454	2006-2008 CAGR	-0.07%
8	Joint pole attachments	454	2006-2008 CAGR	-4.54%
9	Facilities charges	454	2006-2008 CAGR	4.00%
10	Overnight park rents	454	2006-2008 CAGR	0.54%
	Other Electric Revenues			
11	Net Work Service and Other Long Term Firm	456	Fixed & Other Adjustment	
12	Point-to-Point	456	Fixed & Other Adjustment	
13	Photovoltaic	456	2008 Actual	
14	Antelope	456	2008 Actual	
15	Sierra Pacific Power Company sales	456	2008 Actual	
16	Stand-by service	456	2008 Actual	
17	Energy Efficiency Rider	456	Removed in its entirety	
18	Miscellaneous	456	2008 Actual	
19	Provision for rate refund - OATT Tariff	449	Removed in its entirety	
	Other Revenues and Expenses			
	Other Revenues			
20	Power Solutions	415	Fixed & Other Adjustment	
21	Hydro Services	415	2008 Actual	
22	Water Management Services	415	2008 Actual	
23	Joint Use (Pole) - Idaho	415	2008 Actual	
24	Joint Use (Pole) - Oregon	415	2008 Actual	
	Other Expenses			
25	Power Solutions	416	Fixed & Other Adjustment	
26	Hydro Services	416	Removed in its entirety	
27	Water Management Services	416	2008 Actual	
28	Joint Use (Pole) - Idaho	416	2008 Actual	
29	Joint Use (Pole) - Oregon	416	2008 Actual	
	Operations and Maintenance Expenses			
	Power production expenses			
30	Steam power generation(excluding account 501)	500-514	2004-2008 CAGR	3.68%
31	Fuel expense	501	Normalized	
32	Hydraulic power generation (excluding account 536.002 water for power)	535-545	Fixed & Other Adjustment	3.53%
33	Water for power	536.002	2008 Actual	
34	Other power generation(excluding 547)	546-554	Fixed & Other Adjustment	29.94%
35	Fuel expense	547	Normalized	
	Other power supply expenses			
36	Purchased power	555	Normalized	
37	System control and load dispatch	556	Fixed & Other Adjustment	29.94%
38	Other expenses(excluding PCA expense)	557	Fixed & Other Adjustment	29.94%
39	Transmission expenses(excluding account 565)	560-573	Fixed & Other Adjustment	-1.70%
40	Operation - Transmission of electricity by others	565	2008 Actual	
41	Distribution expenses	580-598	Fixed & Other Adjustment	-5.17%
42	Customer account, service and information expenses (excluding uncollectible accounts 904.000 & .001)	901-912	Fixed & Other Adjustment	5.02%
43	Uncollectible Accounts	904.000 &.001	Fixed & Other Adjustment	
44	Administrative and general expenses (excluding accounts 908, 920.001, 928 & 930.1)	920-935	Fixed & Other Adjustment	-0.11%
45	Energy Efficiency Rider	908.131	Removed in its entirety	
46	Incentive	920.001	Annualized (Exhibit No. 501)	
47	Regulatory commission expenses	928	Fixed & Other Adjustment	-0.11%
48	General Advertising	930.1	Removed in its entirety	

IDAHO POWER COMPANY
Forecast Methodology Summary
2009 Test Year

LINE NO	Description	(1) FERC ACCOUNT NUMBER	(2) Methodology	(3) Growth Percentage
	Depreciation and Amortization Expense			
49	Depreciation	403	Fixed & Other Adjustment	
50	Amortization	404	Fixed & Other Adjustment	
	Electric Plant/Regulatory Assets - Amort, Adj, Gains & Losses			
51	Amortization of electric plant acquisition adjustment-Prairie Power	406	2008 Actual	
52	**Regulatory Debits and Credits**	407.3	NONE	
	Taxes Other Than Income			
53	Real and personal property	408.1	Fixed & Other Adjustment	
54	Kilowatt-hour tax - Idaho	408.1	Normalized	
	Licenses			
55	Wyoming	408.1	2006-2008 CAGR	-1.11%
56	Nevada	408.1	2008 Actual	
57	Shoshone-Bannock	408.1	2008 Actual	
	Regulatory commission			
58	Idaho	408.1	Fixed & Other Adjustment	
59	Oregon	408.1	2006-2008 CAGR	8.19%
60	Franchise tax - Oregon	408.1	2006-2008 CAGR	3.67%
61	**Idaho Energy Resources Statement of Income**	418.1/419	Fixed & Other Adjustment	
	Rate Base Components			
	Electric Plant-In-Service			
62	Projects > $2 million	101	Fixed & Other Adjustment	
63	Projects < $2 million	101	2008 Actual	
	Accumulated Reserve for Depreciation and Amortization			
64	Depreciation reserve	108	Fixed & Other Adjustment	
65	Amortization reserve	111	Fixed & Other Adjustment	
	Materials and Supplies			
66	Plant materials and operating supplies	154	2008 Actual	
67	Stores expense undistributed	163	2008 Actual	
68	**Deferred Conservation Programs**	182.3	Fixed & Other Adjustment	
69	**Other Deferred Programs(excluding FERC Grid West Expense)**	182.3/186.722/186.770	Fixed & Other Adjustment	
70	**Plant Held for Future Use(excluding Lakeshore Substation)**	105	2008 Actual	
71	**Deferred Income Taxes**	190/282/283	Fixed & Other Adjustment	
72	**Customer Advances For Construction**	252	Fixed & Other Adjustment	
73	**IERCO-Subsidiary Rate Base Components**	123.1/186/145	Fixed & Other Adjustment	

Idaho Power/506
Witness: Catherine M. Miller

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Catherine M. Miller
Forecast Methodology Manual

July 31, 2009

FORECAST METHODOLOGY MANUAL
2009 RATE CASE

Table of Contents

INTRODUCTION

The purpose of the Forecast Methodology Manual is to provide a reference document that provides supporting detail for the methodologies and multipliers that have been used to set the values contained in IPC's proposed 2009 Test Year. These values were provided to Idaho Power Company ("IPC") witness Bowman for appropriate application to the Uniform System of Accounts for determination of revenue requirement in the 2009 Test Year. The manual is organized in three sections and includes:

- Forecast Methods. Forecast Methods includes a description of the forecast methodologies used to develop the 2009 Unadjusted Forecast Year from the 2008 actual financial data.

- Cost of Service Components. Cost of Service Components includes a description of the three digit account number specified in the Uniform System of Accounts adopted by the Commission and the FERC and the forecast method for each major account or account group.

- Rate Base Components. Rate Base Components includes a description of the three digit account number specified in the Uniform System of Accounts adopted by the Commission and the FERC and the forecast method applied for each major account or account group.

FORECAST METHODS

Updates to the 2008 actual financial data to IPC's proposed 2009 Test Year were developed using one of the following three forecast methods:

(1) Compound Annual Growth Rates ("CAGRs"). Application of a 2006-2008 or a 2004-2008 CAGR to 2008 actual activity and amounts.

The formula for the CAGR:

$$\text{CAGR} = \left(\frac{\text{Ending Value}}{\text{Beginning Value}}\right)^{\left(\frac{1}{\text{\# of Periods}}\right)} - 1$$

(2) Fixed & Other Adjustments. Fixed and Other Adjustments are based on known or probable factors for 2009 that relate to a particular account. Examples of these factors include but are not limited to new billing and volume contract terms, discontinued services, anticipated levels of economic activity, and existing regulatory commission orders.

(3) 2008 Actuals. 2008 actual financial data was used when the Company believed that certain amounts would continue to remain at 2008 levels or account balances were very small.

COST OF SERVICE COMPONENTS

OTHER OPERATING REVENUES
FERC Accounts 451-456 – Table 4

Description. Account 451 includes revenues for all miscellaneous services and charges billed to customers that are not specifically provided for in other accounts. This includes fees for changing, connecting, or disconnecting services and profit on maintenance or installations on customers' premises. Miscellaneous service revenues include continuous service reversion charges (Idaho only), field visit charges, return trip charges, returned check fees, service connection charges, service establishment charges, and application and processing fees collected for new permits, new leases, or requests for easement relinquishments. Account 454 includes rents received for the use by others of land, buildings, and other property devoted to electric operations by IPC such as joint pole attachments, facilities charges, and line and substation rents. Account 456 includes revenues derived from electric operations not includable in other revenue accounts. For example, compensation for minor services provided for others, such as engineering and revenues from transmission of electricity of others over transmission facilities of IPC, such as network and point-to-point wheeling.

Forecast Methodology. Accounts 451 through 456 used a combination of the methodologies for projecting 2009 amounts depending on the nature of the specific account activity being forecast.

- Account 451. Miscellaneous Service Revenues was projected using a three-year CAGR of -17.75% applied to 2008 actual revenues. The decline is consistent with the current slowdown in the economy.

- Account 454. Rent from Electric Property was projected based on either the carry-forward of 2008 Actuals or the 2006-2008 CAGR methodologies depending on the type of 2009 rent to be projected:

  - Transformer rentals, substation equipment rentals, and station and line rentals were projected to be the same in 2009 as 2008 Actual amounts.

  - Each of the remaining Account 454 rents was determined by applying the 2006-2008 CAGR to 2008 Actual amounts. The resulting 2006-2008 CAGR increases by rent type are: (1) cogeneration and small power production (4.66%), (2) real estate (3.07%), (3) facilities charges (4.00%), and (4) overnight park rents (.54%). Decreases by rent type are: (1) dark fiber (-.07%) and (2) pole attachments (-4.54%).

- Account 456. Other Electric Revenues was projected based on either the carry-forward of 2008 Actual amounts or other known factors methodologies depending on the type of 2009 revenue to be projected:

  - Revenues related to the photovoltaic station service, Antelope substation, Sierra Pacific usage charge, stand-by service, and miscellaneous were projected for 2009 to be the same as the 2008 actual amounts.

  - The 2009 point-to-point ("PTP") wheeling revenues were calculated based on nine months of the 2008 equivalent KWhs times the formula based FERC transmission rate, effective October 1, 2008, through September 30, 2009, and three months of the 2008 equivalent KWhs times the forecasted transmission rate. The three-quarters and one-quarter year revenue calculation split is due to the fact that the current transmission rate is in effect from October 1, 2008, until September 30, 2009, and the forecasted rate would become effective October 1, 2009.

  - The 2009 Network Transmission Customer revenues were calculated based on nine months of the network transmission customers' average load ratio share times the formula-based FERC transmission revenue requirement, effective October 1, 2008, through September 30, 2009, and three months of the network transmission customers' average load ratio share times the forecasted FERC transmission revenue requirement. The timing for the Transmission Revenue Requirement is the same as the point-to-point wheeling rate described above. The 2009 estimated network customer MW demand used to calculate the Network Transmission Customer revenue was calculated by taking 2007 MW demand and escalating it using a 2% annual growth factor.

OTHER REVENUES AND OTHER EXPENSES
FERC Accounts 415-416 (excluding 415.002 and 416.002) – Tables 4 and 5

Description. Accounts 415 through 416 include, respectively, all revenues derived from the sale of merchandise and jobbing or contract work and all expenses incurred in such activities. For Idaho Power, jobbing and contract work revenues and expenses include activities related to Idaho Power Solutions, water management services, and joint pole use.

Forecast Methodology. Account 415 (Other Revenues) and Account 416 (Other Expenses) were projected based on either the carry-forward of 2008 actual amounts or other known factors:

- Idaho Power Solutions 2008 Actual Account 415 (Other Revenues) was reduced for services that are no longer being performed. The 2009 reduction is a result of Idaho Power Solutions no longer providing substation services or engineering construction services at Mountain Home Air Force Base, which was the bulk of its revenues. Idaho Power Solutions projected 2009 expenses are expected to match its Account 415 revenues.

- Account 415 (Other Revenues) and Account 416 (Other Expenses) related to Water Management Services and Joint Use (Pole) – Idaho remained at 2008 actual amounts for 2009.

OPERATIONS AND MAINTENANCE EXPENSES ("O&M")
FERC Accounts 500-900 – Table 5

Overview. The following O&M discussion has been organized by functional account groups. Within each account group, a general description of the account has been provided. Most forecasted O&M accounts were developed by segregating the historical financial data between labor and non-labor expense components as follows:

1. Labor. 2009 gross wages were developed by applying the 2004-2008 gross labor expense CAGR of 6.85% to 2008 actual gross wages. The 2008 actual O&M wages to gross wages percentage was applied to the resulting 2009 gross wages to produce a straight time O&M labor amount, the prior year actual labor loading percentage was applied to gross up the straight time amount for health care and other benefits as well as vacation accrual and prior year overtime and other payroll were added to develop a total 2009 O&M labor amount which resulted in a 6.56% increase over 2008 actual O&M labor. This amount was allocated to FERC accounts based on actual 2008 labor charges to FERC accounts.

2. Non-Labor. 2004-2008 CAGRs were calculated for each individual FERC account group (Steam, Hydro, Other Power Generation, Transmission, Distribution, Customer Accounting, Service and Selling, and Administrative and General) and excluded fuel expense, purchased power, property insurance, uncollectable accounts, transmission of electricity by others, energy efficiency expense, water for power (leased water), and incentive expense as these accounts were addressed separately. The weighted average 2004-2008 CAGR for all account grouping's non-labor expenses is 6.75%. The Company believes the 2004-2008 CAGRs for non-labor O&M are the most appropriate method for estimating non-labor O&M; however, given the current downturn in the economy and the impact of the recent extended drought, the Company, where possible, has taken steps to reduce spending, in some cases to below 2008 Actual levels. Had the weighted average 2004-2008 CAGRs of 6.75% been applied, non-labor O&M expense would have increased

$9.9 million from 2008 Actual levels. Instead, after reducing spending targets, 2009 Unadjusted Forecast Year non-labor O&M expense is $4.9 million lower than 2008 Actual levels.

Once O&M labor and non-labor amounts were determined, the results were combined as a percentage representing positive or negative growth for each functional account group and applied to 2008 Actual functional account group. The result was then allocated to FERC accounts based on 2008 Actual FERC account balances.

IPC identified specific exceptions to the forecast methodology described above. Those exceptions include fuel expense, purchased power, property insurance, uncollectable accounts, transmission of electricity by others, energy efficiency expense, water for power (leased water), and incentive expense. These items are discussed separately within their respective account group below.

STEAM POWER GENERATION
FERC Accounts 500-514

Description. Accounts 500 through 514 include the labor, materials, and expenses incurred to operate and maintain prime movers, generators, and their auxiliary apparatus, switch gear, and other electric equipment used in steam power generation. Additionally, the labor and expenses incurred in the general supervision and direction of maintenance of steam generation facilities are included in these accounts.

Accounts 500-514 – Excluding Account 501, Fuel Expense. For Accounts 500-514, excluding fuel expense, the combined 2004-2008 CAGR of 3.68% was applied to 2008 actual expenses. This rate is the combination of the 2004-2008 CAGR of 3.66% for non-labor expense and the 6.56% escalator for O&M labor. Increases were driven by higher chemical costs, such as soda liquor for scrubbers and sulfur for SO3 injection systems; freight costs; contractor pricing for unit overhauls; and labor expense escalation for employees of the plant operating partner.

Account 501, Fuel Expense. Fuel expense has been normalized and is addressed by Scott Wright.

HYDRAULIC POWER GENERATION
FERC Accounts 535-545

Description. Accounts 535 through 545 include the labor, materials used, and expenses incurred to operate and maintain hydraulic works including structures, reservoirs, dams, waterways, generators, roads and bridges, and expenses directly related to the hydroelectric development outside the generating station, including fish and wildlife and recreational facilities. These accounts also include the labor and expenses incurred in the general supervision and direction of maintenance of hydraulic power generating stations, rents of property of others used, occupied, or operated in connection with hydraulic power generation, including amounts payable to the United States for the occupancy of public lands and reservations for reservoirs, dams, flumes, forebays, penstocks, and power houses.

Accounts 535-545 – Excluding Account 536.002, Water for Power. Accounts 535-545, excluding water leases, were escalated at a combined rate of 3.53%. Although the 2004-2008 CAGR for non-labor expense is 7.76%, non-labor expense was held at 2008 spending levels in response to the current economic downturn. O&M Labor expense was escalated at 6.56% as described in the overview section above.

Account 536.002, Water for Power. 2008 Actual amounts have been carried forward as the projection for 2009.

OTHER POWER GENERATION
FERC Accounts 546-557

Description. Accounts 546 through 554 include the operation labor, materials used, and expenses incurred in operating and maintaining prime movers, generators, and electric equipment in other power generating stations. Labor and expenses incurred in the general supervision and direction of maintenance of other power generating stations are also included in these accounts. Account 556 includes labor and expenses incurred in load dispatching activities for system control. System control activities include the production and dispatching of electricity. Account 557 includes production expenses incurred directly in connection with the purchase of electricity which is not specifically provided for in other production expense accounts.

Accounts 546-557 – Excluding Account 547, Fuel Expense, and Accounts 555-557, Purchased Power. Accounts 546-557, excluding fuel expense and purchased power accounts, were escalated at a combined rate of 29.94%. Although the 2004-2008 CAGR for non-labor expense is 17.8%, non-labor expenses were held constant, in total, due to the expectation of absorbing cost increases by managing deferrable activities. An additional expense of $1.2 million for a hot gas path inspection and resulting estimated costs that will occur at Evander Andrews Complex –CT2 in 2009 was added, resulting in an escalation factor of 91.21%. When combined with the 6.56% O&M labor escalator, the accounts were grown at 29.94%.

Account 547, Fuel Expense, and Accounts 555-557, Purchased Power. Fuel expense and purchased power expense have been normalized and are addressed by Scott Wright.

TRANSMISSION EXPENSES
FERC Accounts 560-573

Description. Accounts 560 through 573 include the operation labor, materials used, and expenses incurred in the system planning, operation, executing the reliability coordination function, monitoring, assessing, and operating the power system and individual transmission facilities in real-time to maintain safe and reliable operation of the transmission system specified. Additional activities include: processing the hourly, daily, weekly, and monthly transmission service requests using an automated system such as an Open Access Same-Time Information System ("OASIS"); billing to transmission owners for system control and dispatching service; and conducting transmission services studies for proposed transmission interconnections and generation interconnection with the transmission system. These accounts include the labor, materials used, and expenses incurred in the operation of transmission substations, switching stations, and transmission lines. The use of transmission facilities owned by others and rents of property used, occupied, or operated in connection with the transmission system are also part of this account. The accounts also include the labor, materials used, and expenses incurred in the maintenance of structures, computer hardware and software, communication equipment, miscellaneous transmission plant, station equipment, and transmission plant serving the transmission function.

Accounts 560-573 – Excluding Account 565, Transmission of Electricity by Others. Accounts 560-573, excluding third-party transmission, were decreased by a combined -1.7% from 2008 Actual levels. Although the 2004-2008 non-labor CAGR was a positive 2.58%, due to the continuing economic and resulting customer growth slowdown, expected non-labor expense has been reduced by -14.09% from 2008 levels. When combined with the O&M labor escalator of 6.56%, this account group has been reduced by 1.7% from 2008 levels. The reduction to non-labor expense is expected to be realized in purchased services, materials, and transportation expenses.

Account 565, Transmission of Electricity by Others. 2008 actual amounts have been carried forward as the projection for 2009.

DISTRIBUTION EXPENSES
FERC Accounts 580-598

Description. Accounts 580 through 598 include labor, materials used, and expenses incurred in the general supervision and direction of the operation of the distribution system such as station operation, overhead and underground line operation, meter department operation of customer meters and associated equipment, load dispatching operations, work on customer installations, and inspecting premises. Also included in these accounts are the labor, materials used, and expenses incurred in the general supervision and direction of the maintenance of the distribution system, including maintenance of structures, distribution plant, overhead distribution line facilities, underground distribution line facilities, distribution line transformers, meters, and meter testing equipment.

Accounts 580-598. Accounts 580-598 have been adjusted by a combined factor of -5.17%. The 2004-2008 CAGR for non-labor distribution expense was 4.24%. However, again, as a result of the continuing economic and resulting customer growth slowdown, non-labor expense has been adjusted downward by -23.62% from 2008 levels. Combining the non-labor factor of -23.62% and the O&M labor escalator of 6.56% resulted in a combined adjusted CAGR of –5.17%. Areas of cost reductions relative to 2004-2008 CAGR are expected in purchased services, materials, and transportation expenses.

CUSTOMER ACCOUNTING AND CUSTOMER SERVICES AND INFORMATION EXPENSES
FERC Accounts 901-905 and 907-912

Description. Accounts 901 through 905 include the labor, materials used, and expenses incurred in the general direction and supervision of customer accounting and collecting activities, including reading customer meters, work on customer applications, contracts, orders, credit investigations, billing and accounting, collections, and complaints. These accounts also include the accounting for losses from uncollectible utility revenues. Accounts 907 through 912 include the labor and expenses incurred in customer service and informational activities to encourage safe and efficient use of the utility's service, to encourage conservation of the utility's service, and answer specific inquiries as to proper use of the service and equipment utilizing the service.

Accounts 901-905 and 907-912 – Excluding Account 904, Uncollectible Accounts, and Account 908.131, Idaho Energy Efficiency Rider. Accounts 901-905 and 907-912, excluding uncollectible accounts expense and energy efficiency expenses, were escalated at a combined rate of 5.02%. The 2004-2008 CAGR for non-labor expenses as calculated for customer accounting, customer services, and information O&M expenses was 10.50%. However, once again, due to the continuing economic and resulting customer growth slowdown, the non-labor growth factor has been adjusted downward to 3.04%. Combining the non-labor factor of 3.04% and the 6.56% O&M labor escalator resulted in a combined growth rate of 5.02%. While the economy and customer growth continue to slow, the deterioration requires Idaho Power to continue to maintain a high level of customer service to increased field inquiries. The growth in this area is attributable primarily to increases in labor.

Account 904, Uncollectible Accounts. As a result of the economic downturn, IPC is experiencing higher than normal bad debts. IPC looked at several alternatives to estimate this account including three and five year CAGR and the year-over-year increase from 2007 to 2008. Each of these methods produced unrealistic results. However, the method that provides the most reasonable estimate was one that applies the loss per dollar of sales ratio from 2002 (which is the most recent historical year in which similar economic conditions were experienced) to the 2009 sales, which yielded an estimate of $4.7 million for write-offs for residential and commercial customers. In all methods, the forecasted write-offs for industrial and irrigation customers were held constant at $350,000, which when combined with the residential and commercial estimate, yields $5 million for uncollectible accounts. The $350,000 estimate is based on prior, but conservative, estimates.

Account 908.131, Idaho Energy Efficiency Rider. As addressed by Doug Jones, expenses associated with the Idaho Energy Efficiency Rider have been excluded from this 2009 Test Year (Idaho Public Utilities Commission Order No. 30189).

ADMINISTRATION AND GENERAL EXPENSES ("A&G")
FERC Accounts 920-935

Description. Accounts 920 through 935 include activities undertaken in connection with the utility's general and administrative operations that are assignable to specific administrative or general departments and are not specifically provided for in other accounts. A&G accounts include: (1) compensation of officers, executives, and other employees of the utility which are properly chargeable to utility operations but not chargeable directly to a particular operating function, (2) office supplies and expenses, (3) fees and expenses of professional consultants and others for general services which are not applicable to a particular operating function, (4) insurance or reserve accruals to protect the utility against losses and damages to owned or leased property used in its utility operations, (5) payments for employee accident, sickness, hospital, and death benefits or insurance, (6) payments to municipal or other governmental authorities, (7) the cost of materials, supplies, and services furnished to such authorities without reimbursement in compliance with franchise, ordinance, or similar requirements, (8) expenses incurred by the utility in connection with formal cases before regulatory commissions or other regulatory bodies, (9) regulatory fees assessed against the utility, (10) commission expenses, (11) payments made to the United States for the administration of the Federal Power Act, (12) materials used and expenses incurred in advertising and related activities, (13) rents properly includable in operating expenses for the property of others used, occupied, or operated in connection with customer accounts, customer service, and informational sales and general and administrative functions of the utility, and (14) operation and maintenance of transportation equipment and the maintenance of utility property which is not chargeable directly to a particular operating function.

Accounts 520-935 – Excluding Account 920.001, Incentive Expense, and Account 924, Property Insurance Expense. Accounts 520-935, excluding incentive and property insurance expenses addressed below, were reduced by -0.11% from 2008 levels. The 2004-2008 CAGR for non-labor expense was 9.57%. However, due to the decreased rate of customer growth and the current economic situation, non-labor A&G expenses are expected to be slightly below 2008 levels resulting in an non-labor forecast adjustment factor of -6.21%. Combining the non-labor factor of -6.21% and the O&M labor escalator of 6.56% resulted in a combined adjusted CAGR of -0.11%. Areas of cost reductions relative to the 2004-2008 CAGR driven growth are expected in purchased services, software maintenance expenses, and employee training and travel.

Account 920.001, Incentive Expense. Incentive expense has been excluded from 2009 Unadjusted Forecast Year as it is determined through a normalizing adjustment for the 2009 Test Year. See Exhibit No. 501.

Account 924, Property Insurance Expense. Property Insurance premiums for 2009 are "fixed or known" due to a pre-negotiated rate. Reportable insured values have increased approximately 11.73% due to inflation factors and newly added equipment.

DEPRECIATION AND AMORTIZATION EXPENSE
FERC Accounts 403 and 404 – Table 6

Description. Account 403 includes depreciation expense for all classes of depreciable electric plant in service except such depreciation expense as is chargeable to clearing accounts or to Account 416, Costs and Expenses of Merchandising, Jobbing and Contract Work. Account 404 includes amortization charges applicable to amounts included in the electric plant accounts for limited-term franchises, licenses, patent rights, limited-term interest in land, and expenditures on leased property where the service life of the improvements is terminable by action of the lease. The charges to this account are such as to distribute the book cost of each investment as evenly as may be over the period of its benefit to the utility.

Forecast Methodology. Depreciation and amortization rates were applied to the monthly estimated plant balances (see the Account 101 discussion in the *Rate Base Components* section). The depreciation rates authorized by IPUC Order No. 30639 were used for the entire 2009 Test Year. Parties to the Company's OPUC depreciation filing (UM 1395) have filed a Stipulation Agreement in support of these rates, although an order has not been issued. Several FERC plant accounts have sub-accounts, for which the individual sub-account data was used to calculate a composite rate and applied at the major account level.

For plant accounts 392, Transportation Equipment; 396-Power Operated Equipment; 312, Boiler Plant Equipment; and 397, Communication Equipment, either all or part of the depreciation expense is recorded to other accounts and not Account 403. The Account 312, Boiler Plant Equipment, and Account 397, Communication Equipment, depreciation amounts were calculated using the actual 312.300 and 397.300 accrual for January 2009.

DEPRECIATION AND AMORTIZATION EXPENSE ADJUSTMENTS, GAINS AND LOSSES
FERC Accounts 406 and 411.6 – Table 6

Description. Account 406 is debited or credited, as the case may be, with amounts includable in operating expenses, pursuant to approval or order of the Commission, for the purpose of providing for the extinguishment of the amount in Account 114, Electric Plant Acquisition Adjustments. Account 411.6 includes, as approved by the Commission, amounts relating to gains from the disposition of future use utility plant, including amounts which were previously recorded in and transferred from Account 105, Electric Plant Held for Future Use.

Forecast Methodology.

- Account 406 projected 2009 remained the same as the 2008 Actual amounts. The amount in this account is for the Prairie Power acquisition adjustment and represents the amortization of Account 114 over 233 months at $1,894 per month. The amount in Account 114 will be fully amortized in August 2012.

- Account 411.6 is estimated to be to be zero since there is no plan to sell utility plant in 2009.

TAXES OTHER THAN INCOME TAXES
FERC Account 408.1 – Table 7

Description. Account 408.1 includes those taxes other than income taxes which relate to utility operating income. This account is maintained so as to allow ready identification of the various classes of taxes relating to utility operation, plant leased to others, and other operating income.

Forecast Methodology. 2009 projected Taxes Other Than Income Taxes were based on a combination of known and measurable adjustments arising from facts of particular account activity, carry-forward of 2008 Actual amounts, and application of a three-year CAGR to other account activity.

- Real and Personal Property Taxes. Property taxes are not amenable to the three-year CAGR assumption due to tax anomalies in the Idaho jurisdiction. In 2006, Idaho property taxes were $10.3 million, compared to $9.9 million and $10.9 million in 2007 and 2008, respectively. The 2007 decrease is primarily a result of a change to Bennett Mountain power plant apportionment methodology.

  The methodology used to project property taxes for the 2009 Test Year is the same estimation process used for establishing the annual property tax accrual for IPC financial statements. Property taxes are estimated using both an appraisal and levy methodology. For the appraisal methodology, actual appraisal data is used to the extent known, and each state's historical appraisal methodologies and trends are used in determining the appraisal amount. For the tax levy methodology, the state's historical levy data and local government budget policy is used to estimate levies. Because of different states' property tax years, the period to be projected varies. Idaho, Wyoming, and Montana were estimated for all 2009 as those bills are not received until the end of the calendar year. Oregon and Nevada required estimates for the last half of 2009 as split year states. And, the Shoshone-Bannock tax represented the actual 2009 amount billed.

- Idaho kWh Taxes. Test Year 2009 kWh taxes were projected based on normalized hydro conditions and normalized consumption.

- Regulatory Commission Fees. For IPC, the calculated three-year CAGR for Idaho regulatory fees resulted in a growth rate of 1.35% due to the formulaic manner in which the IPUC allocates its approved budget to utilities based on pro rata utility revenues and thus is not indicative of future trend factors. Therefore, a known and measurable adjustment was used. The 2009 IPUC budget as recommended by Idaho's governor indicated a decline of 2.0% from 2008 levels. The -2.0% growth in fees is a result of the utility share of the 2009 IPUC budget $5.0 million compared to prior year utility share 2008 budget of $5.1 million. Oregon regulatory fees were increased 8.19% based on a three-year CAGR.

- Licenses. Wyoming, Nevada, and Shoshone-Bannock projected 2009 license fees were based on the three-year CAGR resulting in -1.11%, 0.00%, and 0.00%, respectively.

- Franchises. Test year 2009 Oregon franchise taxes were projected using a three-year CAGR of 3.67%.

IDAHO ENERGY RESOURCES CO. ("IERCO") COST OF SERVICE COMPONENTS FERC Accounts 418.1 and 419

Description. Account 418.1 includes the utility's equity in the earnings or losses of subsidiary companies for the year. Account 419 includes interest revenues on securities, loans, notes, advances, special deposits, tax refunds, all other interest-bearing assets, and dividends on stocks of other companies, whether the securities on which the interest and dividends are received are carried as investments or included in sinking or other special fund accounts.

Forecast Methodology. IPC owns 100% of Idaho Energy Resource Company ("IERCO"), which has a one-third joint venture interest in Bridger Coal Company ("BCC"), a mine that supplies coal to the Jim Bridger plant. PacifiCorp, Inc., owns the remaining two-thirds interest and is the mine's operating partner. As a one-third owner in BCC, IERCO is entitled to 33% of the BCC net income and cash flows. IPC's projected 2009 cost of service of $6.1 million for IERCO is based on PacifiCorp, Inc.'s projected activity for the BCC mine.

IERCO overriding royalties are determined by the location and lease under which BCC is mining. The three leases are with BLM, Union Pacific Railroad, and State of Wyoming, and each lease pays at a different rate. The overriding royalty was granted to BCC from IERCO, who in turn received them from IPC as advance royalties in the past. Coal royalty payments have no impact on IERCO's net income as revenue is recognized when paid by BCC, and expense recognized when remitted to IPC.

Income taxes are calculated at the federal tax rate of 35% as Wyoming has no state income tax. Taxes are accrued and paid during the calendar year. In past years, a favorable 2006 IRS ruling allowed IERCO to take a $2.0 million depletion deduction for calculating taxable income. Recent depletion computations by PacifiCorp indicate no depletion deductions will be available for 2009. Therefore, no depletion adjustment has been included in the 2009 Test Year.

As discussed in the Rate Base Components section that follows, IERCO maintains an intercompany note with IPC that accrues interest monthly at IPC's short-term borrowing rate. For purposes of the Cost of Service Component of IERCO, the intercompany interest expense net of income tax is added back to increase IERCO's net income.

RATE BASE COMPONENTS

ELECTRIC PLANT IN SERVICE
FERC Account 101 – Table 1

Description. This account includes the original cost of electric plant that is included in Accounts 301 to 399 (referred to herein as plant accounts). It is described as being owned and used by the utility in its electric utility operations and having an expectation of life in service of more than one year from date of installation, including such property owned by the utility but held by nominees. The cost of additions to and improvements of property leased from others, which are includable in this account, are recorded in subdivisions separate and distinct from those relating to owned property.

Forecast Methodology. The methodologies used for plant additions and retirements are described below.

PLANT ADDITIONS TO ACCOUNT 101

Projected 2009 plant additions to Account 101 were developed based on the size of Construction Work in Process ("CWIP") projects as of year-end 2008 plus expected 2009 capital expenditures. These capital projects were segregated into pools of greater than and less than $2 million. Capital projects greater than $2 million were considered to be known and measureable. For capital projects less than $2 million, a historical methodology was developed. Once CWIP project types for both pools were determined, the results were allocated to FERC plant accounts 301 through 399 using a four year historical average. This methodology is consistent with that used in Idaho's 2008 Rate Case (Case No. IPC-E-08-10).

1. **Projected 2009 Plant Additions**

   a. Capital Projects in Excess of $2 Million. Large capital projects with total costs in excess of $2 million were determined to be known and measurable adjustments for the 2009 Unadjusted Forecast Year. Actual capital expenditures in CWIP as of year-end 2008, plus expected future capital expenditures were used to calculate the amount that would close to plant by year-end 2009. An Allowance for Funds Used During Construction ("AFUDC") was accrued on the CWIP balances at an AFUDC rate of approximately 7.1%. The AFUDC rate was based on the historical four year average actual AFUDC rate from 2005 through 2008. In addition, these projects' capital account balances, projected expenditures, and the timing of closes to plant have been reviewed by business unit managers familiar with the projects.

The total amounts for the plant additions in the pool of over $2 million in capital expenditures are assigned CWIP project types based on the particular project's nature.

b. Capital Projects Less Than $2 Million. For smaller capital projects with total capital expenditures less than $2 million, IPC determined that the five-year CAGR is typically the most appropriate method to use to project 2009 plant additions because the method smoothes out fluctuations between years. The calculated five-year CAGR growth rate was 10.46%. However, in recognition of the current market conditions, anticipated 2009 plant closings were set equal to actual 2008 plant closings.

The total amounts for the plant additions in the pool of under $2 million in capital expenditures were then allocated to the CWIP project types based on a three-year historical average.

Vehicle purchases were considered in total as a single project for this purpose.

2. Allocation to FERC Plant Account

The above CWIP project type pools were combined for final allocation to FERC plant accounts. For that allocation, actual final closings from CWIP Account 107 to Plant Account 101 were analyzed for the four-year period 2005 through 2008. The 2005 through 2008 time frame was selected due to the change from in-plant accounting in 2004, which would have skewed the closings to FERC Plant Accounts 368, Transformers, and 370, Meters. Final closing amounts in the PeopleSoft Asset Management system were used to allocate closings to plant accounts rather than pre-closure amounts. Final closes represent the "as built" property units after the construction and work order has been completed and reconciled, whereas pre-closes are based on work order estimates and may not be reflective of the final close amount. For each CWIP project type, the percentage allocation to FERC plant accounts 301 through 399 was determined by the ratio of the four-year historical plant account closing for that CWIP project type.

RETIREMENTS FROM ACCOUNT 101

Retirements were analyzed for the four-year period 2005 through 2008. Retirements by FERC plant account were determined and compared to the closings by FERC plant account for the same period. Retirements by FERC plant account were estimated by calculating the historical percentage of retirements to additions for the four-year period.

The following FERC plant accounts have known retirement dates based on vintage layers and were not estimated:

- 302 Software
- 303 Franchises and Consents
- 391 Furniture
- 393 Stores Equipment
- 394 Shop Tools
- 395 Laboratory Equipment
- 397 Communication Equipment
- 398 Miscellaneous Equipment

ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION
FERC Accounts 108 and 111 – Table 2

Description. Account 108 is credited for amounts charged to Account 403, Depreciation Expense, or to clearing accounts for current depreciation expense for electric plant in service. At the time of retirement of depreciable electric utility plant, this account is charged with the book cost of the property retired and cost of removal and then credited with the salvage value and any other amounts recovered such as insurance. When retired, costs of removal and salvage are originally entered in retirement work orders, the net total of such work orders may be included in a separate subaccount hereunder. Upon completion of the work order, the proper distribution to subdivisions of this account shall be made for general ledger and balance sheet purposes as a single composite provision for depreciation. For purposes of analysis, however, each utility shall maintain subsidiary records in which this account is segregated according to the functional classification of electric plant in service. Account 111 is credited with amounts charged to Account 404, Amortization of Limited-Term Electric Plant, for the current amortization of limited-term electric plant investments.

Forecast Methodology. The accumulated provision for depreciation and amortization has been presented using a thirteen month average. To determine the 2009 thirteen month account balances, the year-end 2008 accumulated depreciation and amortization account balances were rolled forward monthly using the estimated 2009 depreciation and amortization expense accruals, retirements, salvage, and removal costs. See Account 403 and 404 in the *Cost of Service Components* section for discussion with respect to the depreciation and amortization accrual calculation and Account 101 in the *Rate Base Components* section for discussion of the method of determining retirements. The five-year average salvage and removal costs were then calculated. The salvage and removal averages as a percentage of the retirement average were used to estimate monthly salvage and removal costs. Those amounts were allocated to the transmission and distribution FERC plant accounts in their respective ratio to estimated retirements.

MATERIALS AND SUPPLIES
FERC Accounts 154 and 163 – Table 3

Description. Account 154 includes the cost of materials purchased primarily for use in the utility business for construction, operation, and maintenance purposes. Materials and supplies issued are credited hereto and charged to the appropriate construction, operating expense, or other account on the basis of a unit price determined by the method of inventory accounting. Account 163 includes the cost of supervision, labor, and expenses incurred in the operation of general storerooms, including purchasing, storage, handling, and distribution of materials and supplies. This account is cleared by adding to the cost of materials and supplies issued a suitable loading charge which distributes the expense equitably over stores issues. The balance in the account at the close of the year shall not exceed the amount of stores expenses reasonably attributable to the inventory of materials and supplies.

Forecast Methodology. Due to current economic conditions and a slowing in customer growth, 2009 forecast was projected to be the same as 2008 actuals.

OTHER DEFERRED PROGRAMS
FERC Accounts 182.3 and 186 – Table 3

Description. This account includes the amounts of regulatory assets not includable in other accounts resulting from the ratemaking actions of regulatory agencies.

Methods to Update to 2009 Levels

- Account 182.360, Deferred Conservation Programs, IPUC Order Nos. 27660, 27722, and 28041. This account is amortized at $270,217 per month or $3,242,604 annually and will be fully amortized by July 2010.

- Accounts 186.722 and 186.770, American Falls Bond Refinancing, IPUC Order No. 25880. These deferred costs are financing costs related to American Falls Bond issuances. The total monthly amortization of these two bonds is $5,212 per month or $62,551 per year. These deferrals will be fully amortized by 2025.

- Account 182.368, Intervenor Funding, IPUC Order No. 30035. This intervenor funding is related to the 2005 Rate Case No. IPC-E-05-28. Recovery of this amount was included in the 2007 Rate Case No. IPC-E-07-08 and therefore the balance has been removed. The cost will be fully amortized by December 31, 2009.

- Account 182.307, Intervenor Funding, IPUC Order No. 30215. This intervenor funding is related to the Load Growth Adjustment Rate filing. Recovery of this amount was included in the 2007 Rate Case No. IPC-E-

07-08 and therefore the balance has been removed. The cost will be fully amortized by December 31, 2009.

- Account 182.308, Intervenor Funding, IPUC Order No. 30267. This intervenor funding is related to the Fixed Cost Adjustment filing. Recovery of this amount was included in the 2007 Rate Case No. IPC-E-07-08, and therefore the balance has been removed. The cost will be fully amortized by December 31, 2009.

- Account 182.342, Intervenor Funding, IPUC Order No. 30488. This intervenor funding is related to the Wind Powered Small Power Production filing. Recovery of the cost was included in the 2007 Rate Case No. IPC-E-07-08. The total 2009 amortization equals $23,808. The cost will be fully amortized by January 2010.

- Account 182.343, Intervenor Funding, IPUC Order No. 30508. This intervenor funding is related to 2007 Rate Case No. IPC-E-07-08. Recovery of the cost was included in the 2007 Rate Case No. IPC-E-07-08. The total 2009 amortization equals $38,775. The cost will be fully amortized by January 2010.

- Account 182.349, Intervenor Funding, IPUC Order No. 30722. This intervenor funding is related to 2008 Rate Case No. IPC-E-08-10. Recovery of this amount is included in the current test year. The cost will be fully amortized by December 2009.

- Account 182.350 – Intervenor Funding – IPUC Order No. 30722. This intervenor funding is related to 2008 Rate Case No. IPC-E-08-10. Recovery of this amount is included in the current test year. The cost will be fully amortized by December 2009.

- Account 182.348, Architect Services, IPUC Order No. 30722. Per the order for the 2008 Rate Case No. IPC-E-08-10, the ratemaking treatment of this cost incurred in 2008 is to defer the expense and amortize it over three years. Recovery of this amount is included in the current test year. The cost will be fully amortized by December 2010.

- Account 182.369, Grid West Loans, OPUC Order No. 06-483. The ratemaking treatment for the Oregon portion of the Grid West loans was deferred for a ratemaking procedure. The amortization period was to be determined at that time. IPC is currently accruing interest on the Oregon portion at Oregon's authorized rate of return of 7.83% per annum. The accrued balance at December 31, 2009, including interest will be $69,751.

- Account 182.304, Grid West Loans, FERC Portion. The 2009 amount includes the FERC portion of the Grid West loan and incremental costs. The FERC order reflecting recovery of these costs went into effect May 2008 and will be recovered over a five-year period. The 2008 balance has been reduced by $83,796 for 2009 amortization to determine the projected 2009 balance.

PLANT HELD FOR FUTURE USE
FERC Account 105 – Table 3

Description. This account includes the original cost of electric plant owned and held for future use in electric service under a definite plan for such use and includes property acquired but never used by the utility in electric service, but held for such service in the future under a definite plan, and property previously used by the utility in service, but retired from such service and held pending its reuse in the future, under a definite plan, in electric service.

Forecast Methodology. IPC has not included any 2009 projected acquisitions. The 2009 forecast was projected to be the same as the 2008 Base.

CUSTOMER ADVANCES FOR CONSTRUCTION ("CAC")
FERC Account 252 – Table 3

Description. Account 252 includes advances by customers for construction which are to be partially or wholly refunded. When a customer is refunded the entire amount to which he or she is entitled according to the agreement or rule under which the advance was made, any remaining balance is credited to the appropriate plant account.

Forecast Methodology. IPC looked at both the three and five year CAGR to forecast this account; however, both of these methods provided unrealistic results because customer advances are driven primarily by customer growth. Therefore, an average balance dollar per customer methodology was used. This average dollar balance per customer was calculated by taking the sum of the customer additions for the five-year period from 2004 through 2008 and dividing that into the 2008 Account 252 balance excluding the 2008 network upgrade deposits. This average balance per customer was then multiplied by the sum of the customer additions for the projected five-year period from 2005 through 2009 and then added to the forecasted 2009 network upgrade deposit balance. Network upgrade deposits are generator interconnection deposits to upgrade existing facilities in order to connect the generator and are refundable.

IDAHO ENERGY RESOURCES CO. ("IERCO") RATE BASE
FERC Accounts 123.1, 186, and 145 – Table 3

Description. Account 123.1 includes the cost of investments in securities issued or assumed by subsidiary companies and investment advances to such companies, including interest accrued thereon when such interest is not subject to current settlement plus the equity in undistributed earnings or losses of such subsidiary companies since acquisition. This account is credited with any dividends declared by such subsidiaries. This account is maintained in such a manner as to show separately for each subsidiary: (1) the cost of such investments in the securities of the subsidiary at the time of acquisition, (2) the amount of equity in the subsidiary's undistributed net earnings or net losses since acquisition, and (3) advances or loans to such subsidiary. Account 145 represents notes receivable from associated companies. Account 186 includes all debits not elsewhere provided for, such as miscellaneous work in progress, and unusual or extraordinary expenses, not included in other accounts, which are in process or amortization and items the proper final disposition of which is uncertain.

Forecast Methodology. IPC's projected 2009 investment in IERCO is based on expected activity for 2009 at the Bridger Coal Company ("BCC") mine that supplies coal to the Jim Bridger thermal plant. As a one-third owner in BCC, IERCO is entitled to 33% of the BCC net income and cash flows.

- Account 123.1, Investment in IERCO. IERCO's investment in BCC is accounted for using the equity method. BCC income, IERCO income, and IERCO capital contributions to BCC increase the investment balance, while BCC dividend distributions to IERCO reduce the investment balance. The investment in IERCO balance is projected to increase $6.3 million from the 2008 base thirteen month average balance of $56.1 million to the 2009 thirteen month average balance of $62.4 million. See the IERCO *Cost of Service Component* section for further discussion of BCC revenues.

- Account 186, Prepaid Coal Royalties. BCC overriding coal royalties are determined by the location and lease under which BCC is mining. The overriding royalty was granted to BCC from IERCO, who in turn received them from IPC as advance royalties in the past. Although coal royalty payments have no impact on IERCO's net income because revenue is recognized when paid by BCC and expense recognized when remitted back to IPC, the payment flow serves to reduce the Account 186 balance. 2009 thirteen month average advance coal royalties are projected to be $69,325. As a result, the thirteen month average Account 186 balance decreases by $69,325 from the 2008 base thirteen month average balance of $1.6 million to a 2009 thirteen month average balance of $1.5 million.

- Account 145, Notes Payable To/Receivable from Subsidiary. The IERCO intercompany note is the funding mechanism whereby IERCO not only receives distributions from and makes capital contributions to BBC but also pays income taxes and dividends to IPC. The intercompany note activity is based on the 2009 BCC operating and investing cash budgets. As no excess cash is projected by BCC in 2009, IERCO has no scheduled dividend for IPC. The thirteen month average intercompany note decreases $2.2 million from $25.6 million for 2008 base to $23.4 million for 2009. Interest on the intercompany note is based on IPC's short-term borrowing rates and accrues monthly. The average interest rate used for 2009 is 2.1%.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE _______

IN THE MATTER OF THE APPLICATION	)
OF IDAHO POWER COMPANY FOR	)
AUTHORITY TO INCREASE ITS RATES	)
AND CHARGES FOR ELECTRIC	)
SERVICE IN THE STATE OF OREGON.	)
	)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

SCOTT L. WRIGHT

July 31, 2009

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

A. My name is Scott L. Wright. 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 educational background.

A. I received a Bachelor of Science degree in Business Economics from Eastern Oregon University. I have attended the Center for Public Utilities College of Business Administration and Economics Practical Skills for a Changing Electric course in Albuquerque, New Mexico.

Q. Please describe your work experience?

A. In May 1998, I accepted a position as Research Assistant with Idaho Power Company in the Pricing and Regulatory Services Department. In March 2007, I was promoted to a Pricing Analyst. As a Pricing Analyst, I am responsible for running the AURORAxmp model to calculate net power supply expenses ("NPSE") for ratemaking purposes, along with the marginal cost of energy used in the Company's marginal cost analysis. In December 2007, I was assigned the task of working on Bonneville Power Administration's Average System Cost Methodology and the WP-07 Supplemental rate case proceeding. I also provide analytical support for other regulatory activities within the Pricing and Regulatory Services Department.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the Company's variable power supply expenses under the Company's 2009 Test Year ("2009 Test Year" or "Test Year") and compare those results to variable power supply expenses currently reflected in rates as a result of the Company's 2008 October Update, the first portion of the Annual Power Cost Update ("APCU"). As described in Company witness Gregory Said's testimony, the

Company is not proposing to update the variable power supply expenses that have been modeled for the 2009 Test Year; instead, the Company is proposing to continue using the variable power supply expenses from the Company's 2008 October Update. As a result, the purpose of my testimony is to provide updated power supply expenses for informational purposes only.

Q. How are variable power supply expenses "normalized" for ratemaking purposes?

A. Variable power supply expenses are determined for each water condition starting with 1928. In this case, 81 water conditions have been evaluated. The average of the 81 water conditions is considered a reasonable representation of power supply expenses the Company might encounter during the test year.

Q. Please define the term "power supply expense" as the Company and the Commission have used the term historically.

A. The Company and the Commission have used the term "power supply expense" to refer to the sum of fuel expenses (FERC Accounts 501 and 547) and purchased power expenses (FERC Account 555), excluding PURPA qualifying facilities ("QF") expenses minus surplus sales revenues (FERC Account 447). For ratemaking purposes, QF expenses have been quantified separately from other power supply expenses and are treated as fixed inputs to power supply modeling rather than variable inputs.

Q. Please describe the changes in the Company's system loads since the 2008 October Update.

A. The Company's 2008 October Update annual normalized system load was 16.4 million megawatt-hours ("MWh"). The Company's 2009 annual normalized system load used in this scenario is 16.3 million MWh, a decrease of 0.1 million MWh.

Q. Are any large loads expected to come on-line during this scenario?

A. Yes. Hoku Materials, Inc. ("Hoku"), a manufacturer of solar panels, is expected to come on-line in 2009.

Q. Please explain the Hoku contract.

A. The Electric Service Agreement ("ESA") between the Company and Hoku is separated into two blocks. The first block of the contract charges market based rates, while the second block charges embedded rates. The first block revenues are subtracted from the NPSE in a similar manner to the treatment of surplus sales, which also reduce NPSE.

Q. How is the Hoku ESA treated in your NPSE calculations?

A. The Hoku ESA loads were annualized at 2010 levels to include the time period when rates will become effective, while first block revenues were subtracted from the NPSE as mentioned above.

Q. Was Hoku included in the 2008 October Update?

A. Yes. The Hoku load was included in the 2008 October Update for the April 2009 through March 2010 time period; however, no other adjustments were made.

Q. How have the fuel costs of the Company's coal-fired resources changed since the 2008 October Update?

A. The fuel cost for the Bridger plant has seen a moderate increase, from $15.83 per MWh to $18.58 per MWh, while coal costs have increased only minimally for Boardman (from $16.42 per MWh to $16.92 per MWh) and Valmy (from $25.23 per MWh to $25.29 per MWh).

Q. Please explain why coal costs have increased since the 2008 October Update for the Bridger plant.

A. A change in the Bridger coal contract reflects the higher cost of coal due to increased mining and transportation costs.

Q. Please explain how the increased cost of coal affects variable power supply expenses.

A. On a normalized basis, the Company's coal plants supply approximately 38 percent of the Company's required generation. When coal costs increase, the Company's variable power supply expenses also increase.

Q. Have natural gas prices changed since the 2008 October Update?

A. Yes. Natural gas prices have declined since the 2008 October Update. The average Henry Hub gas price for the 2008 October Update was $8.50 per MmBtu, while the average Henry Hub gas price used to prepare the information I am presenting in my testimony is $4.54 per MmBtu.

Q. Please explain how an increase or decrease in natural gas prices affects NPSE.

A. Natural gas prices influence electricity prices within the AURORA model. When natural gas prices are high, surplus sales revenues are larger due to higher market prices, whereas when natural gas prices are low, the inverse occurs. Because Idaho Power is a net seller of electricity under "normal" conditions, a decrease in electricity prices caused by lower gas prices result in an increase in NPSE.

Q. Have any new resources been added since the Company's last general rate case?

A. Yes. The Company has added two additional natural gas-fired peaking units. Bennett Mountain was added in 2005 and Danskin CT1 was added in 2008. When economical, these peaking plants are dispatched to serve system peaks that hydro facilities cannot meet or where traditional purchases cannot be made due to transmission constraints.

Q. Have you prepared an exhibit to demonstrate the normalization of variable power supply expenses describing the changes you have described in your testimony?

A. Yes. Exhibit No. 601 shows the results of the variable power supply expense normalization modeling for the 2009 Test Year. Exhibit No. 601 also shows the summary results containing the 81-year average variable power supply generation sources and expenses.

Q. Please summarize the sources and disposition of energy shown on Exhibit No. 601.

A. Hydro generation supplies 8.6 million megawatt-hours (MWh), approximately 47 percent (8.6 million MWh / 18.2 million MWh = 47 percent) of the generation mix. Thermal generation supplies 7.0 million MWh (Bridger 5.1, Boardman 0.3, Valmy 1.6), approximately 38 percent (7.0 million MWh / 18.2 million MWh = 38 percent) of the generation mix. Danskin and Bennett Mountain are peaking units so they supply energy at times when resources and/or transmission lines are constrained. Purchases of power are made up of short-term and longer-term market purchases and PURPA. PURPA purchases are normalized and account for nearly 1.0 million MWh. PURPA purchases are not included on Exhibit No. 601; however, when combined with market purchases of 1.5 million MWh, total purchases amount to 2.5 million MWh (1.0 million MWh + 1.5 million MWh = 2.5 million MWh) approximately 14 percent (2.5 million MWh / 18.2 million MWh = 14 percent) of the generation mix. Of the 18.2 million MWh consumed, 16.4 million MWh are utilized for system loads while nearly 1.8 million MWh are sold as surplus.

Q. Please describe the expense and revenue information associated with the normalized operation you described in Exhibit No. 601.

A. Exhibit No. 601 contains variable power supply expense and revenue information limited to FERC accounts 501, Fuel (coal); 547, Fuel (gas); 555, Purchased Power; and 447, Sales for Resale. Hydro generation has no assumed fuel expense. Coal expenses of $140.8 million are comprised of Bridger at $94.2 million, Valmy at $41.1 million, and Boardman at $5.5 million. Gas expenses of $6.1 million are comprised of Danskin at $5.5 million and Bennett Mountain at $0.6 million. Purchased Power expenses, not including QF, amount to $69.7 million, surplus sales expenses amount to $46.6 million, and the Hoku first block surplus sales amount to $25.3 million. The NPSE amount to $144.7 million (140.8 + 6.1 + 69.7 – 46.6 - 25.3).

Q. How do these NPSE compare to the 2008 October Update?

A. The NPSE approved in the 2008 October Update was $100.1 million; therefore, the NPSE presented here represents a $44.6 million increase before PURPA repricing.

Q. Please explain why the NPSE in this scenario is higher than the NPSE for the 2008 October Update.

A. This scenario includes updated fuel costs and revised loads. The methodology used in the 2008 October Update used an average of forward market prices to reprice purchased power and surplus sales, while this scenario relies on AURORA to price purchased power and surplus sales.

Q. Please describe the change in PURPA generation and expenses since the 2008 October Update.

A. PURPA generation decreased from 124 aMW to 117 aMW, a reduction of 7 aMW. PURPA expenses also decreased from $63.7 million to $61.2 million, a reduction of $3.2 million. This reduction was caused by several PURPA projects failing to meet their expected on-line dates.

Q. Have PURPA contracts been repriced to reflect the unlevelized avoided costs?

A. No. PURPA contracts were not repriced in the 2008 October Update, and they were not repriced in this scenario. As Mr. Said described in his testimony, the repriced amounts the Company is entitled to will be captured in Power Cost Adjustment Mechanism

("PCAM") deferrals.

Q. What level of NPSE have you provided to Company witness Jeannette Bowman for inclusion into the Jurisdictional Separation Study?

A. I have provided Ms. Bowman the currently approved base NPSE resulting from the 2008 October Update, which was quantified at $163.8 million as shown on Exhibit No. 602.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Scott L. Wright
Power Supply Expense for 2009 Normalized Loads Over
81 Water Year Conditions

July 31, 2009

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
Hoku Annualized
AVERAGE

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	758,578.7	861,819.4	865,173.5	869,278.7	946,375.4	905,747.4	633,747.4	582,057.7	512,831.1	525,469.7	465,261.0	676,415.7	8,602,755.7
Bridger													
Energy (MWh)	469,098.8	411,431.7	444,249.9	353,257.8	319,959.4	351,920.8	456,587.8	456,748.0	430,956.5	455,477.1	452,664.4	470,582.2	5,072,934.4
Cost ($ x 1000)	$ 8,694.2	$ 7,636.0	$ 8,251.7	$ 6,574.9	$ 5,964.1	$ 6,579.5	$ 8,475.1	$ 8,477.3	$ 8,012.0	$ 8,460.2	$ 8,391.4	$ 8,719.5	$ 94,236.0
Boardman													
Energy (MWh)	29,735.5	26,218.5	30,814.2	2,831.5	-	21,821.5	35,646.9	36,036.4	34,725.0	36,399.3	34,886.6	35,629.3	324,744.7
Cost ($ x 1000)	$ 513.2	$ 453.5	$ 526.4	$ 48.4	$ -	$ 380.8	$ 597.0	$ 603.5	$ 582.0	$ 609.0	$ 584.5	$ 598.0	$ 5,496.2
Valmy													
Energy (MWh)	173,323.9	131,595.9	127,522.3	86,611.0	85,047.4	92,954.4	149,693.9	151,134.2	129,258.3	143,796.1	158,305.9	175,674.3	1,604,917.8
Cost ($ x 1000)	$ 4,425.3	$ 3,368.2	$ 3,266.4	$ 2,222.5	$ 2,188.6	$ 2,392.7	$ 3,834.2	$ 3,869.3	$ 3,308.2	$ 3,677.5	$ 4,042.9	$ 4,481.8	$ 41,077.6
Danskin													
Energy (MWh)	0.5	-	-	6.5	0.5	72.6	21,436.3	15,595.2	1,898.3	713.3	664.6	185.9	40,573.7
Cost ($ x 1000)	$ 0.0	$ -	$ -	$ 0.3	$ 0.0	$ 2.8	$ 924.3	$ 673.0	$ 86.5	$ 35.0	$ 37.2	$ 14.0	$ 1,773.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 306.3	$ 315.3	$ 308.7	$ 1,239.6	$ 988.3	$ 392.5	$ 350.2	$ 343.1	$ 329.2	$ 5,491.1
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	1.6	5,573.3	8,399.8	323.1	100.3	45.7	5.5	14,449.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 0.1	$ 244.6	$ 352.5	$ 11.6	$ 4.4	$ 2.3	$ 0.4	$ 615.9
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ 0.1	$ 244.6	$ 352.5	$ 11.6	$ 4.4	$ 2.3	$ 0.4	$ 615.9
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	68,568.9	4,429.4	1,163.5	6,360.1	38,910.2	67,525.4	265,883.9	234,595.3	138,768.2	31,524.8	87,432.9	94,875.2	1,040,037.8
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	98,623.0	27,622.6	26,879.3	33,446.2	69,716.8	131,444.5	333,520.2	295,872.8	160,778.2	62,709.0	117,176.0	131,792.5	1,489,581.0
Market Cost ($ x 1000)	$ 3,896.3	$ 191.0	$ 39.6	$ 217.0	$ 1,313.1	$ 2,159.9	$ 13,232.3	$ 9,398.5	$ 5,492.2	$ 1,311.6	$ 4,226.3	$ 5,495.4	$ 46,973.1
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 5,445.2	$ 1,391.6	$ 1,021.6	$ 1,251.6	$ 2,488.2	$ 5,228.2	$ 16,819.1	$ 12,623.8	$ 6,641.9	$ 2,930.1	$ 6,079.7	$ 7,789.0	$ 69,710.0
Surplus Sales													
Energy (MWh)	153,208.4	303,426.7	364,567.5	295,701.6	206,402.4	151,383.3	11,580.0	10,015.5	64,871.8	110,949.6	68,509.2	88,993.2	1,829,609.1
Revenue Including Transmission Costs ($ x 1000)	$ 5,188.6	$ 8,686.5	$ 9,849.4	$ 6,952.6	$ 4,477.9	$ 3,110.3	$ 267.4	$ 265.8	$ 1,629.5	$ 3,097.8	$ 2,055.3	$ 2,838.0	$ 48,418.9
Transmission Costs ($ x 1000)	$ 153.2	$ 303.4	$ 364.6	$ 295.7	$ 206.4	$ 151.4	$ 11.6	$ 10.0	$ 64.9	$ 110.9	$ 68.5	$ 89.0	$ 1,829.6
Revenue Excluding Transmission Costs ($ x 1000)	$ 5,035.3	$ 8,383.0	$ 9,484.8	$ 6,656.9	$ 4,271.5	$ 2,958.9	$ 255.8	$ 255.8	$ 1,564.6	$ 2,986.8	$ 1,986.8	$ 2,749.0	$ 46,589.3
Hoku First Block Surplus Sales Revenue	$ 2,487.3	$ 2,259.6	$ 2,487.3	$ 2,411.4	$ 2,487.3	$ 1,586.5	$ 785.5	$ 1,309.1	$ 2,094.1	$ 2,487.3	$ 2,411.4	$ 2,487.3	$ 25,294.3
Net Power Supply Expense ($ x 1000)	$ 11,870.5	$ 2,494.0	$ 1,409.2	$ 1,335.4	$ 4,197.4	$ 10,344.7	$ 30,168.3	$ 25,349.7	$ 15,289.3	$ 10,557.3	$ 15,045.7	$ 16,681.6	$ 144,743.1

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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,078,496.9	1,100,179.3	1,042,909.8	1,002,437.1	1,074,929.1	742,634.8	599,479.1	571,476.6	560,723.3	499,921.1	551,265.3	693,218.6	9,517,670.9
Bridger													
Energy (MWh)	470,742.4	425,186.7	470,742.4	380,204.2	339,215.9	371,026.8	470,156.8	469,429.2	449,487.1	469,603.6	455,557.1	470,742.4	5,242,094.5
Cost ($ x 1000)	$ 8,722.2	$ 7,878.1	$ 8,722.2	$ 7,049.4	$ 6,305.8	$ 6,926.9	$ 8,712.2	$ 8,699.8	$ 8,337.4	$ 8,702.8	$ 8,440.8	$ 8,722.2	$ 97,219.8
Boardman													
Energy (MWh)	37,321.9	33,280.1	38,732.5	3,286.3	-	26,509.6	38,013.7	36,027.5	34,994.6	37,102.1	36,060.9	37,545.1	358,874.2
Cost ($ x 1000)	$ 622.1	$ 555.8	$ 642.3	$ 55.6	$ -	$ 459.2	$ 632.0	$ 603.7	$ 586.0	$ 619.0	$ 601.2	$ 625.3	$ 6,002.1
Valmy													
Energy (MWh)	180,348.9	161,611.4	169,696.3	110,930.2	95,435.1	96,993.4	173,393.7	176,896.9	147,037.1	166,606.6	174,481.5	180,348.9	1,833,780.2
Cost ($ x 1000)	$ 4,594.7	$ 4,119.4	$ 4,340.4	$ 2,878.7	$ 2,488.8	$ 2,516.0	$ 4,419.3	$ 4,507.6	$ 3,790.6	$ 4,266.7	$ 4,445.3	$ 4,594.7	$ 46,962.3
Danskin													
Energy (MWh)	-	-	-	-	-	-	35,356.0	12,590.9	512.3	146.5	189.5	20.3	48,815.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,328.5	$ 484.5	$ 20.2	$ 6.1	$ 9.6	$ 1.2	$ 1,850.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 1,643.8	$ 799.7	$ 326.1	$ 321.3	$ 315.5	$ 316.5	$ 5,567.9
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	17,123.8	8,400.0	208.0	71.8	-	-	25,803.7
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 648.0	$ 325.3	$ 8.3	$ 3.0	$ -	$ -	$ 984.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 648.0	$ 325.3	$ 8.3	$ 3.0	$ -	$ -	$ 984.6
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	-	-	-	-	966.7	91,860.0	229,456.9	215,925.6	77,452.7	24,321.8	26,719.1	57,735.1	724,437.9
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	31,773.3	155,779.2	297,093.2	277,203.0	99,462.7	55,506.0	56,462.1	94,652.4	1,173,981.1
Market Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ 28.6	$ 2,427.4	$ 15,621.0	$ 7,911.9	$ 2,741.5	$ 931.0	$ 1,226.6	$ 2,979.8	$ 33,867.7
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,203.7	$ 5,495.7	$ 19,207.8	$ 11,137.2	$ 3,891.2	$ 2,549.5	$ 3,080.1	$ 5,273.4	$ 56,604.6
Surplus Sales													
Energy (MWh)	420,812.1	588,189.1	617,725.1	474,213.9	326,656.3	40,364.2	5,990.8	16,195.6	86,526.3	115,242.5	113,521.4	75,235.5	2,880,672.7
Revenue Including Transmission Costs ($ x 1000)	$ 20,098.2	$ 19,020.8	$ 18,391.2	$ 11,306.7	$ 7,718.0	$ 1,003.6	$ 150.2	$ 412.5	$ 2,205.1	$ 3,077.8	$ 3,432.2	$ 2,577.2	$ 89,393.4
Transmission Costs ($ x 1000)	$ 420.8	$ 588.2	$ 617.7	$ 474.2	$ 326.7	$ 40.4	$ 6.0	$ 16.2	$ 86.5	$ 115.2	$ 113.5	$ 75.2	$ 2,880.7
Revenue Excluding Transmission Costs ($ x 1000)	$ 19,677.3	$ 18,432.6	$ 17,773.5	$ 10,832.4	$ 7,391.4	$ 963.2	$ 144.3	$ 396.3	$ 2,118.6	$ 2,962.5	$ 3,318.6	$ 2,501.9	$ 86,512.7
Net Power Supply Expense ($ x 1000)	$ (3,874.2)	$ (4,391.4)	$ (2,771.4)	$ 491.8	$ 2,922.1	$ 14,740.4	$ 35,118.9	$ 25,677.0	$ 14,821.0	$ 13,499.8	$ 13,564.3	$ 17,030.2	$ 126,828.6

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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	664,131.6	688,750.8	725,937.2	820,822.5	879,536.4	722,642.1	534,614.9	527,213.7	375,134.4	435,365.2	413,195.9	661,184.0	7,448,528.6
Bridger													
Energy (MWh)	470,742.4	425,186.7	470,742.4	383,427.2	350,711.8	385,269.8	470,742.4	470,742.4	455,524.5	470,742.4	455,557.1	470,742.4	5,280,131.5
Cost ($ x 1000)	$ 8,722.2	$ 7,878.1	$ 8,722.2	$ 7,104.4	$ 6,501.7	$ 7,169.6	$ 8,722.2	$ 8,722.2	$ 8,440.3	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 97,868.0
Boardman													
Energy (MWh)	36,884.8	34,239.4	38,022.5	3,654.8	-	27,122.1	38,215.7	37,843.0	36,151.0	37,669.7	37,691.8	38,306.2	365,801.1
Cost ($ x 1000)	$ 615.9	$ 569.5	$ 632.1	$ 60.8	$ -	$ 467.9	$ 634.9	$ 629.6	$ 602.5	$ 627.1	$ 624.5	$ 636.2	$ 6,101.0
Valmy													
Energy (MWh)	180,348.9	162,894.9	179,265.0	150,930.0	143,385.7	157,744.4	180,045.6	180,296.9	174,488.8	180,334.2	174,531.2	180,348.9	2,044,614.6
Cost ($ x 1000)	$ 4,594.7	$ 4,150.0	$ 4,568.8	$ 3,846.5	$ 3,674.4	$ 4,045.9	$ 4,587.5	$ 4,593.5	$ 4,445.5	$ 4,594.4	$ 4,446.5	$ 4,594.7	$ 52,142.5
Danskin													
Energy (MWh)	-	-	-	9.8	-	-	36,809.1	19,954.8	3,817.6	2,042.0	1,594.2	-	64,227.4
Cost ($ x 1000)	$ -	$ -	$ -	$ 0.4	$ -	$ -	$ 1,707.4	$ 949.0	$ 186.0	$ 104.9	$ 99.9	$ -	$ 3,047.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 306.4	$ 315.3	$ 305.9	$ 2,022.7	$ 1,264.3	$ 491.9	$ 420.1	$ 405.8	$ 315.3	$ 6,765.5
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	11,301.0	9,427.4	197.3	308.7	55.0	-	21,289.5
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 528.0	$ 451.0	$ 9.7	$ 16.0	$ 3.5	$ -	$ 1,008.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 528.0	$ 451.0	$ 9.7	$ 16.0	$ 3.5	$ -	$ 1,008.1
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	21,700.9	-	-	-	16,516.8	64,872.9	287,488.4	238,400.4	194,571.9	49,203.7	105,686.8	72,765.2	1,051,206.9
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	51,754.9	23,193.1	25,715.8	27,086.1	47,323.4	128,792.1	355,124.8	299,677.8	216,581.9	80,387.9	135,429.8	109,682.5	1,500,750.1
Market Cost ($ x 1000)	$ 1,334.4	$ -	$ -	$ -	$ 587.4	$ 2,247.0	$ 19,037.5	$ 11,568.6	$ 8,847.8	$ 2,389.8	$ 6,020.7	$ 4,594.0	$ 56,627.4
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 2,883.3	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,762.6	$ 5,315.3	$ 22,624.4	$ 14,793.9	$ 9,997.5	$ 4,008.3	$ 7,874.2	$ 6,887.6	$ 79,364.3
Surplus Sales													
Energy (MWh)	27,710.7	179,003.3	309,611.3	336,200.3	206,260.2	68,990.9	2,227.7	9,327.4	55,996.7	93,135.0	57,560.1	58,971.8	1,404,995.4
Revenue Including Transmission Costs ($ x 1000)	$ 1,564.2	$ 7,766.9	$ 11,067.6	$ 11,083.6	$ 5,475.9	$ 1,855.0	$ 62.5	$ 260.6	$ 1,529.2	$ 2,807.2	$ 2,119.1	$ 2,521.6	$ 48,113.3
Transmission Costs ($ x 1000)	$ 27.7	$ 179.0	$ 309.6	$ 336.2	$ 206.3	$ 69.0	$ 2.2	$ 9.3	$ 56.0	$ 93.1	$ 57.6	$ 59.0	$ 1,405.0
Revenue Excluding Transmission Costs ($ x 1000)	$ 1,536.4	$ 7,587.9	$ 10,758.0	$ 10,747.4	$ 5,269.6	$ 1,786.0	$ 60.2	$ 251.3	$ 1,473.2	$ 2,714.0	$ 2,061.5	$ 2,462.6	$ 46,708.3
Net Power Supply Expense ($ x 1000)	$ 15,595.0	$ 6,497.7	$ 4,462.4	$ 1,605.3	$ 6,984.3	$ 15,518.7	$ 39,059.4	$ 30,203.1	$ 22,514.2	$ 15,674.0	$ 19,733.8	$ 18,693.3	$ 196,541.2

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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	542,187.3	718,004.5	662,257.7	542,452.5	716,973.8	640,409.6	511,558.8	517,170.1	371,901.3	413,195.7	408,008.7	474,965.2	6,519,085.2
Bridger													
Energy (MWh)	470,742.4	425,186.7	470,742.4	383,427.2	352,516.5	392,847.9	470,742.4	470,742.4	455,557.1	470,742.4	455,557.1	470,742.4	5,289,546.9
Cost ($ x 1000)	$ 8,722.2	$ 7,878.1	$ 8,722.2	$ 7,104.4	$ 6,532.4	$ 7,298.8	$ 8,722.2	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 98,028.5
Boardman													
Energy (MWh)	38,826.1	34,179.1	38,669.9	3,539.4	-	28,044.0	38,491.4	37,583.3	36,589.6	38,502.6	37,827.6	39,127.7	371,380.8
Cost ($ x 1000)	$ 643.6	$ 568.6	$ 641.4	$ 59.2	$ -	$ 481.1	$ 638.8	$ 625.9	$ 608.8	$ 639.0	$ 626.5	$ 647.9	$ 6,180.6
Valmy													
Energy (MWh)	180,348.9	162,895.8	179,947.5	150,672.9	148,860.9	162,925.4	180,348.9	180,348.9	174,531.2	180,222.8	174,531.2	180,348.9	2,055,983.8
Cost ($ x 1000)	$ 4,594.7	$ 4,150.1	$ 4,585.1	$ 3,840.4	$ 3,804.9	$ 4,169.5	$ 4,594.7	$ 4,594.7	$ 4,446.5	$ 4,591.7	$ 4,446.5	$ 4,594.7	$ 52,413.5
Danskin													
Energy (MWh)	-	-	-	-	-	-	36,873.2	18,541.6	4,135.3	3,237.8	1,195.0	1,110.4	65,093.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,896.9	$ 977.2	$ 223.5	$ 184.6	$ 83.2	$ 93.0	$ 3,458.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 2,212.2	$ 1,292.4	$ 529.4	$ 499.8	$ 389.1	$ 408.2	$ 7,176.2
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	10,152.2	7,710.5	213.2	314.4	46.0	15.1	18,451.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 526.1	$ 409.2	$ 11.6	$ 18.1	$ 3.2	$ 1.3	$ 969.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 526.1	$ 409.2	$ 11.6	$ 18.1	$ 3.2	$ 1.3	$ 969.4
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	119,633.5	-	-	23,392.3	80,812.2	99,829.8	310,278.8	250,439.2	195,784.1	60,279.7	108,101.7	207,318.3	1,455,869.6
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.3
Total Energy Excl. CSPP (MWh)	149,687.6	23,193.1	25,715.8	50,478.4	111,618.8	163,748.9	377,915.1	311,716.6	217,794.1	91,464.0	137,844.8	244,235.6	1,905,412.9
Market Cost ($ x 1000)	$ 8,785.1	$ -	$ -	$ 987.8	$ 3,308.7	$ 3,929.5	$ 20,953.0	$ 12,827.2	$ 9,923.7	$ 3,294.7	$ 6,802.5	$ 14,544.6	$ 85,356.6
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 10,333.9	$ 1,200.7	$ 981.9	$ 2,022.3	$ 4,483.8	$ 6,997.9	$ 24,539.8	$ 16,052.5	$ 11,073.4	$ 4,913.2	$ 8,656.0	$ 16,838.2	$ 108,093.5
Surplus Sales													
Energy (MWh)	5,640.3	208,197.8	247,261.8	80,840.3	115,272.9	35,396.4	1,456.4	7,984.8	54,823.1	83,964.4	54,515.4	9,253.1	904,606.6
Revenue Including Transmission Costs ($ x 1000)	$ 352.3	$ 9,786.3	$ 9,951.0	$ 2,681.7	$ 2,783.6	$ 888.3	$ 43.6	$ 239.3	$ 1,658.8	$ 2,818.8	$ 2,233.7	$ 424.9	$ 33,862.3
Transmission Costs ($ x 1000)	$ 5.6	$ 208.2	$ 247.3	$ 80.8	$ 115.3	$ 35.4	$ 1.5	$ 8.0	$ 54.8	$ 84.0	$ 54.5	$ 9.3	$ 904.6
Revenue Excluding Transmission Costs ($ x 1000)	$ 346.6	$ 9,578.1	$ 9,703.8	$ 2,600.9	$ 2,668.3	$ 852.9	$ 42.2	$ 231.3	$ 1,604.0	$ 2,734.9	$ 2,179.1	$ 415.6	$ 32,957.7
Net Power Supply Expense ($ x 1000)	$ 24,263.1	$ 4,506.7	$ 5,542.1	$ 10,731.3	$ 12,468.1	$ 18,400.2	$ 41,191.7	$ 31,465.5	$ 23,506.6	$ 16,649.0	$ 20,383.0	$ 30,796.9	$ 239,904.1

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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	462,010.8	483,892.7	614,211.9	525,996.2	586,762.9	485,636.7	479,973.0	490,296.4	340,553.8	356,104.2	400,061.6	472,694.1	5,698,194.4
Bridger													
Energy (MWh)	470,742.4	425,186.7	470,742.4	383,427.2	352,522.1	392,410.6	470,742.4	470,742.4	455,557.1	470,742.4	455,557.1	470,742.4	5,289,115.1
Cost ($ x 1000)	$ 8,722.2	$ 7,878.1	$ 8,722.2	$ 7,104.4	$ 6,532.5	$ 7,291.3	$ 8,722.2	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 98,021.2
Boardman													
Energy (MWh)	38,491.9	34,590.1	38,059.1	3,654.9	-	29,149.7	38,889.1	38,463.4	36,632.8	38,301.5	37,480.6	39,038.0	372,751.1
Cost ($ x 1000)	$ 638.8	$ 574.5	$ 632.7	$ 60.8	$ -	$ 499.7	$ 644.5	$ 638.4	$ 609.4	$ 636.1	$ 621.5	$ 646.6	$ 6,203.1
Valmy													
Energy (MWh)	180,348.9	162,542.2	179,499.1	151,161.4	148,877.8	164,138.4	180,338.9	180,348.3	174,496.9	180,141.4	174,529.1	180,348.9	2,056,771.4
Cost ($ x 1000)	$ 4,594.7	$ 4,141.6	$ 4,574.4	$ 3,852.1	$ 3,805.3	$ 4,198.4	$ 4,594.5	$ 4,594.7	$ 4,445.7	$ 4,589.8	$ 4,446.4	$ 4,594.7	$ 52,432.3
Danskin													
Energy (MWh)	-	-	-	24.8	-	301.3	41,665.2	26,735.0	5,358.1	3,515.8	929.6	687.3	79,217.1
Cost ($ x 1000)	$ -	$ -	$ -	$ 1.3	$ -	$ 15.4	$ 2,150.4	$ 1,415.0	$ 290.5	$ 201.0	$ 64.9	$ 57.7	$ 4,196.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 307.2	$ 315.3	$ 321.3	$ 2,465.6	$ 1,730.3	$ 596.4	$ 516.3	$ 370.9	$ 373.0	$ 7,914.1
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	15,314.9	14,960.8	585.1	296.2	48.6	28.3	31,233.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 796.2	$ 796.4	$ 32.0	$ 17.1	$ 3.4	$ 2.4	$ 1,647.5
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 796.2	$ 796.4	$ 32.0	$ 17.1	$ 3.4	$ 2.4	$ 1,647.5
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	194,998.5	41,347.2	6.7	28,362.5	167,507.3	220,968.3	330,785.9	258,378.7	217,630.3	97,126.6	113,970.0	209,876.5	1,880,958.5
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.3
Total Energy Excl. CSPP (MWh)	225,052.6	64,540.3	25,722.5	55,448.6	198,313.9	284,887.4	398,422.2	319,656.1	239,640.3	128,310.8	143,713.1	246,793.8	2,330,501.8
Market Cost ($ x 1000)	$ 14,154.8	$ 2,131.4	$ 0.4	$ 1,209.3	$ 6,684.1	$ 8,441.6	$ 26,227.2	$ 14,687.3	$ 11,030.2	$ 5,241.2	$ 7,138.4	$ 14,528.2	$ 111,474.0
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 15,703.7	$ 3,332.1	$ 982.3	$ 2,243.9	$ 7,859.3	$ 11,510.0	$ 29,814.0	$ 17,912.6	$ 12,179.9	$ 6,859.6	$ 8,991.8	$ 16,821.8	$ 134,210.9
Surplus Sales													
Energy (MWh)	494.6	15,490.6	198,163.4	69,983.0	71,779.6	3,944.5	719.9	5,373.8	46,925.4	63,697.1	51,824.7	9,040.6	537,437.2
Revenue Including Transmission Costs ($ x 1000)	$ 28.2	$ 710.8	$ 7,714.5	$ 2,344.1	$ 1,607.0	$ 90.3	$ 23.2	$ 166.0	$ 1,415.5	$ 2,073.0	$ 2,103.9	$ 418.7	$ 18,695.3
Transmission Costs ($ x 1000)	$ 0.5	$ 15.5	$ 198.2	$ 70.0	$ 71.8	$ 3.9	$ 0.7	$ 5.4	$ 46.9	$ 63.7	$ 51.8	$ 9.0	$ 537.4
Revenue Excluding Transmission Costs ($ x 1000)	$ 27.7	$ 695.3	$ 7,516.3	$ 2,274.1	$ 1,535.2	$ 86.3	$ 22.5	$ 160.6	$ 1,368.6	$ 2,009.3	$ 2,052.1	$ 409.7	$ 18,157.8
Net Power Supply Expense ($ x 1000)	$ 29,947.0	$ 15,518.3	$ 7,710.5	$ 11,294.2	$ 16,977.1	$ 23,734.4	$ 47,014.5	$ 34,234.0	$ 24,935.6	$ 19,331.7	$ 20,822.8	$ 30,751.0	$ 282,271.2

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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	443,292.8	582,256.8	739,464.0	756,140.8	866,853.6	939,070.5	567,214.3	517,543.5	381,543.8	452,241.2	406,052.0	485,976.7	7,137,649.9
Bridger													
Energy (MWh)	470,742.4	425,186.7	469,584.8	377,832.2	338,837.7	372,394.6	470,304.2	470,691.6	455,376.3	470,742.4	455,557.1	470,742.4	5,247,992.3
Cost ($ x 1000)	$ 8,722.2	$ 7,878.1	$ 8,702.5	$ 7,009.0	$ 6,299.3	$ 6,938.9	$ 8,714.7	$ 8,721.3	$ 8,437.8	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 97,309.0
Boardman													
Energy (MWh)	34,768.3	30,418.0	29,235.1	2,729.0	-	23,239.1	36,271.5	36,643.7	35,613.6	37,592.2	36,185.9	36,747.8	339,444.2
Cost ($ x 1000)	$ 585.7	$ 514.9	$ 506.7	$ 47.6	$ -	$ 409.6	$ 607.1	$ 612.5	$ 594.9	$ 626.0	$ 603.0	$ 613.9	$ 5,722.0
Valmy													
Energy (MWh)	180,100.8	162,514.9	161,476.5	130,539.2	134,498.3	147,777.9	178,679.6	179,708.7	174,463.4	180,340.8	174,445.3	180,348.9	1,984,894.4
Cost ($ x 1000)	$ 4,588.8	$ 4,141.0	$ 4,144.4	$ 3,359.9	$ 3,462.5	$ 3,798.7	$ 4,554.8	$ 4,579.4	$ 4,444.9	$ 4,594.5	$ 4,444.4	$ 4,594.7	$ 50,708.0
Danskin													
Energy (MWh)	-	-	-	-	-	-	16,872.2	16,077.5	2,236.7	1,060.4	699.6	5.2	36,951.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 746.8	$ 728.9	$ 104.0	$ 52.0	$ 41.8	$ 0.4	$ 1,673.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 1,062.1	$ 1,044.2	$ 409.9	$ 367.2	$ 347.7	$ 315.6	$ 5,391.7
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	911.8	5,009.2	250.7	196.8	49.2	-	6,417.7
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 40.7	$ 228.6	$ 11.7	$ 9.7	$ 3.0	$ -	$ 293.7
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 40.7	$ 228.6	$ 11.7	$ 9.7	$ 3.0	$ -	$ 293.7
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	217,716.7	9,337.8	-	-	11,656.8	23,418.0	290,299.1	255,725.6	190,219.8	40,468.6	111,333.9	200,931.4	1,351,107.7
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	247,770.8	32,530.9	25,715.8	27,086.1	42,463.4	87,337.2	357,935.4	317,003.0	212,229.8	71,652.8	141,076.9	237,848.7	1,800,650.9
Market Cost ($ x 1000)	$ 12,372.5	$ 359.5	$ -	$ -	$ 375.7	$ 655.1	$ 12,661.4	$ 10,971.8	$ 8,158.7	$ 1,869.4	$ 5,828.1	$ 11,384.3	$ 64,636.5
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 13,921.4	$ 1,560.2	$ 981.9	$ 1,034.6	$ 1,550.9	$ 3,723.5	$ 16,248.2	$ 14,197.1	$ 9,308.4	$ 3,487.8	$ 7,681.5	$ 13,677.9	$ 87,373.4
Surplus Sales													
Energy (MWh)	522.9	77,645.8	295,404.5	244,597.2	167,955.8	217,239.7	3,563.4	6,848.6	55,815.6	100,111.4	53,571.1	10,377.5	1,233,653.6
Revenue Including Transmission Costs ($ x 1000)	$ 24.2	$ 2,917.8	$ 8,796.0	$ 6,603.0	$ 4,193.4	$ 5,946.0	$ 90.3	$ 178.2	$ 1,467.5	$ 2,903.9	$ 1,761.0	$ 357.6	$ 35,238.8
Transmission Costs ($ x 1000)	$ 0.5	$ 77.6	$ 295.4	$ 244.6	$ 168.0	$ 217.2	$ 3.6	$ 6.8	$ 55.8	$ 100.1	$ 53.6	$ 10.4	$ 1,233.7
Revenue Excluding Transmission Costs ($ x 1000)	$ 23.7	$ 2,840.2	$ 8,500.6	$ 6,358.4	$ 4,025.4	$ 5,728.7	$ 86.7	$ 171.4	$ 1,411.6	$ 2,803.8	$ 1,707.4	$ 347.2	$ 34,005.2
Net Power Supply Expense ($ x 1000)	$ 28,109.7	$ 11,541.3	$ 6,150.2	$ 5,398.6	$ 7,602.5	$ 9,447.9	$ 31,140.9	$ 29,211.7	$ 21,795.8	$ 15,003.6	$ 19,813.1	$ 27,577.1	$ 212,792.6

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	449,297.7	636,111.6	550,384.2	655,171.3	675,004.5	979,002.3	540,393.9	526,233.4	382,212.4	444,492.3	407,250.7	495,764.3	6,741,318.6
Bridger													
Energy (MWh)	470,742.4	425,186.7	470,418.4	382,915.5	348,891.2	388,826.3	469,963.2	470,592.5	455,131.5	470,671.0	455,557.1	470,742.4	5,279,638.1
Cost ($ x 1000)	$ 8,722.2	$ 7,878.1	$ 8,716.7	$ 7,095.6	$ 6,470.7	$ 7,230.2	$ 8,708.9	$ 8,719.6	$ 8,433.6	$ 8,721.0	$ 8,440.8	$ 8,722.2	$ 97,859.6
Boardman													
Energy (MWh)	29,275.7	28,274.2	33,150.7	3,172.6	-	10,851.8	34,241.7	35,883.9	35,317.3	35,371.3	33,011.4	30,233.1	308,783.7
Cost ($ x 1000)	$ 507.3	$ 484.3	$ 562.6	$ 53.9	$ -	$ 202.3	$ 578.2	$ 601.6	$ 590.6	$ 594.3	$ 557.7	$ 521.0	$ 5,253.9
Valmy													
Energy (MWh)	179,867.9	161,379.9	173,647.0	141,912.7	142,307.3	149,634.8	175,477.7	179,383.1	174,243.0	179,387.1	174,113.7	178,969.7	2,010,324.0
Cost ($ x 1000)	$ 4,583.2	$ 4,113.8	$ 4,434.7	$ 3,631.3	$ 3,648.7	$ 3,843.0	$ 4,478.4	$ 4,571.6	$ 4,439.6	$ 4,571.7	$ 4,436.5	$ 4,561.8	$ 51,314.3
Danskin													
Energy (MWh)	-	-	-	-	-	-	14,210.6	11,492.4	1,529.4	-	-	-	27,232.4
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 659.1	$ 545.7	$ 74.5	$ -	$ -	$ -	$ 1,279.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 974.4	$ 861.0	$ 380.4	$ 315.3	$ 305.9	$ 315.3	$ 4,997.2
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	336.3	2,020.5	23.5	-	-	-	2,380.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 15.7	$ 96.7	$ 1.2	$ -	$ -	$ -	$ 113.5
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 15.7	$ 96.7	$ 1.2	$ -	$ -	$ -	$ 113.5
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	217,833.1	442.7	3,057.7	1,037.3	110,230.1	17,230.8	323,813.4	257,067.2	190,616.3	46,537.2	112,800.2	198,511.0	1,479,176.7
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	247,887.2	23,635.8	28,773.5	28,123.5	141,036.7	81,150.0	391,449.7	318,344.6	212,626.2	77,721.4	142,543.2	235,428.3	1,928,719.9
Market Cost ($ x 1000)	$ 11,445.6	$ 13.1	$ 130.8	$ 37.8	$ 3,903.8	$ 538.8	$ 14,362.4	$ 11,120.9	$ 8,370.5	$ 2,033.4	$ 5,623.7	$ 10,074.3	$ 67,655.1
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 12,994.5	$ 1,213.8	$ 1,112.8	$ 1,072.4	$ 5,078.9	$ 3,607.2	$ 17,949.3	$ 14,346.2	$ 9,520.2	$ 3,651.8	$ 7,477.1	$ 12,367.9	$ 90,392.0
Surplus Sales													
Energy (MWh)	918.9	119,326.7	126,302.1	161,565.5	92,542.6	256,885.6	1,447.6	8,121.7	55,184.4	93,927.9	51,981.2	9,845.5	978,049.6
Revenue Including Transmission Costs ($ x 1000)	$ 44.3	$ 4,434.6	$ 4,000.1	$ 4,805.9	$ 2,142.9	$ 6,382.5	$ 36.4	$ 215.4	$ 1,451.4	$ 2,599.5	$ 1,553.6	$ 263.9	$ 27,930.6
Transmission Costs ($ x 1000)	$ 0.9	$ 119.3	$ 126.3	$ 161.6	$ 92.5	$ 256.9	$ 1.4	$ 8.1	$ 55.2	$ 93.9	$ 52.0	$ 9.8	$ 978.0
Revenue Excluding Transmission Costs ($ x 1000)	$ 43.3	$ 4,315.3	$ 3,873.8	$ 4,644.4	$ 2,050.4	$ 6,125.6	$ 35.0	$ 207.3	$ 1,396.2	$ 2,505.6	$ 1,501.6	$ 254.1	$ 26,952.5
Net Power Supply Expense ($ x 1000)	$ 27,079.1	$ 9,662.1	$ 11,268.2	$ 7,514.8	$ 13,463.1	$ 9,063.0	$ 32,669.9	$ 28,989.4	$ 21,969.4	$ 15,348.5	$ 19,716.5	$ 26,234.0	$ 222,978.0

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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	532,581.1	547,634.2	513,205.1	509,749.3	745,901.2	348,796.5	391,231.0	470,657.2	332,716.4	388,329.2	399,281.9	466,100.8	5,646,184.0
Bridger													
Energy (MWh)	470,742.4	423,832.7	467,292.1	380,803.3	343,676.0	392,052.5	470,742.4	470,742.4	455,557.1	470,742.4	455,557.1	470,742.4	5,272,482.7
Cost ($ x 1000)	$ 8,722.2	$ 7,855.0	$ 8,663.4	$ 7,059.6	$ 6,381.8	$ 7,285.2	$ 8,722.2	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 97,737.7
Boardman													
Energy (MWh)	21,785.6	23,133.9	28,821.0	2,683.6	-	30,140.5	37,997.9	37,640.2	36,131.3	38,043.0	35,982.2	36,911.9	329,271.1
Cost ($ x 1000)	$ 391.7	$ 411.0	$ 500.8	$ 47.0	$ -	$ 513.9	$ 631.8	$ 626.7	$ 602.3	$ 632.4	$ 600.1	$ 616.3	$ 5,573.9
Valmy													
Energy (MWh)	172,666.7	146,631.0	164,905.7	129,446.2	131,919.5	163,141.8	180,171.5	180,348.9	174,524.7	180,212.0	174,478.9	180,013.5	1,978,460.3
Cost ($ x 1000)	$ 4,411.3	$ 3,759.6	$ 4,226.2	$ 3,333.8	$ 3,396.2	$ 4,174.7	$ 4,590.5	$ 4,594.7	$ 4,446.3	$ 4,591.4	$ 4,445.2	$ 4,586.7	$ 50,556.8
Danskin													
Energy (MWh)	-	-	-	-	-	1,389.7	38,745.0	22,072.2	5,116.5	1,670.7	529.6	532.6	70,056.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 64.6	$ 1,819.3	$ 1,062.5	$ 252.3	$ 86.9	$ 33.6	$ 40.6	$ 3,359.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 370.5	$ 2,134.5	$ 1,377.8	$ 558.3	$ 402.1	$ 339.5	$ 355.9	$ 7,077.6
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	120.6	10,525.9	9,380.0	517.2	113.6	-	-	20,657.4
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 5.6	$ 497.9	$ 454.2	$ 25.7	$ 6.0	$ -	$ -	$ 989.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ 5.6	$ 497.9	$ 454.2	$ 25.7	$ 6.0	$ -	$ -	$ 989.4
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	149,388.3	24,918.5	7,573.2	37,626.6	64,288.8	353,059.4	427,589.0	287,799.9	223,718.3	77,143.1	115,385.4	216,019.0	1,984,509.5
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	179,442.3	48,111.6	33,289.1	64,712.7	95,095.4	416,978.6	495,225.3	349,077.4	245,728.2	108,327.3	145,128.4	252,936.3	2,434,052.7
Market Cost ($ x 1000)	$ 6,682.3	$ 677.1	$ 262.8	$ 1,136.7	$ 2,153.0	$ 12,520.4	$ 33,083.8	$ 13,948.3	$ 10,324.8	$ 3,726.4	$ 6,340.1	$ 12,985.3	$ 103,841.1
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 8,231.2	$ 1,877.8	$ 1,244.7	$ 2,171.3	$ 3,328.1	$ 15,588.8	$ 36,670.7	$ 17,173.6	$ 11,474.4	$ 5,344.8	$ 8,193.6	$ 15,278.9	$ 126,578.0
Surplus Sales													
Energy (MWh)	1,066.1	34,082.0	77,441.3	37,664.9	101,895.0	40.8	13.4	4,089.6	44,392.7	73,723.0	50,463.1	5,945.3	430,817.0
Revenue Including Transmission Costs ($ x 1000)	$ 48.5	$ 1,129.2	$ 2,176.8	$ 947.9	$ 2,266.3	$ 1.0	$ 0.3	$ 108.8	$ 1,198.3	$ 2,206.6	$ 1,734.8	$ 224.3	$ 12,042.7
Transmission Costs ($ x 1000)	$ 1.1	$ 34.1	$ 77.4	$ 37.7	$ 101.9	$ 0.0	$ 0.0	$ 4.1	$ 44.4	$ 73.7	$ 50.5	$ 5.9	$ 430.8
Revenue Excluding Transmission Costs ($ x 1000)	$ 47.4	$ 1,095.1	$ 2,099.4	$ 910.3	$ 2,164.4	$ 0.9	$ 0.3	$ 104.7	$ 1,153.9	$ 2,132.8	$ 1,684.3	$ 218.3	$ 11,611.9
Net Power Supply Expense ($ x 1000)	$ 22,024.3	$ 13,095.7	$ 12,851.0	$ 12,007.3	$ 11,257.0	$ 27,937.8	$ 53,247.2	$ 32,844.5	$ 24,393.9	$ 17,566.1	$ 20,335.0	$ 29,341.6	$ 276,901.5

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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	440,949.3	492,215.5	486,077.9	579,030.9	630,748.6	589,878.8	494,465.1	494,581.6	348,839.3	405,415.0	403,938.8	467,481.5	5,833,622.3
Bridger													
Energy (MWh)	470,742.4	425,186.7	470,658.2	383,427.2	350,791.5	388,556.2	470,496.0	470,742.4	455,557.1	470,742.4	455,557.1	470,742.4	5,283,199.5
Cost ($ x 1000)	$ 8,722.2	$ 7,878.1	$ 8,720.8	$ 7,104.4	$ 6,503.0	$ 7,225.6	$ 8,718.0	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 97,920.3
Boardman													
Energy (MWh)	31,580.1	30,807.3	34,846.8	3,536.9	-	25,504.5	36,636.2	37,178.9	36,338.8	38,235.8	37,626.3	38,731.8	351,023.5
Cost ($ x 1000)	$ 540.2	$ 520.5	$ 586.8	$ 59.1	$ -	$ 444.8	$ 612.3	$ 620.1	$ 605.2	$ 635.2	$ 623.6	$ 642.3	$ 5,890.1
Valmy													
Energy (MWh)	179,650.7	162,300.1	178,097.5	148,411.1	145,626.4	157,984.0	178,355.8	180,201.2	174,344.5	180,256.9	174,531.2	180,348.9	2,040,108.4
Cost ($ x 1000)	$ 4,578.0	$ 4,135.8	$ 4,541.0	$ 3,786.4	$ 3,727.8	$ 4,051.6	$ 4,547.1	$ 4,591.2	$ 4,442.0	$ 4,592.5	$ 4,446.5	$ 4,594.7	$ 52,034.6
Danskin													
Energy (MWh)	-	-	-	-	-	-	22,627.2	19,318.4	3,984.4	2,893.0	1,114.7	1,820.0	51,757.7
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,117.9	$ 977.6	$ 206.8	$ 158.3	$ 74.5	$ 146.2	$ 2,681.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 1,433.1	$ 1,292.9	$ 512.7	$ 473.6	$ 380.4	$ 461.4	$ 6,399.1
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	1,888.3	6,800.3	382.2	346.5	31.8	105.1	9,554.2
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 94.0	$ 346.5	$ 20.0	$ 19.1	$ 2.1	$ 8.5	$ 490.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 94.0	$ 346.5	$ 20.0	$ 19.1	$ 2.1	$ 8.5	$ 490.2
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	223,275.8	34,564.6	12,487.4	9,383.2	131,415.0	138,508.4	353,206.8	271,370.7	212,382.9	65,000.9	110,921.9	213,516.0	1,776,033.6
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	253,329.9	57,757.8	38,203.2	36,469.3	162,221.6	202,427.6	420,843.1	332,648.2	234,392.9	96,185.1	140,664.9	250,433.3	2,225,576.8
Market Cost ($ x 1000)	$ 12,987.4	$ 1,475.4	$ 573.7	$ 374.2	$ 5,124.9	$ 4,921.6	$ 19,395.8	$ 13,240.6	$ 10,276.7	$ 3,390.5	$ 6,734.0	$ 14,254.7	$ 92,749.5
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 14,536.3	$ 2,676.0	$ 1,555.7	$ 1,408.7	$ 6,300.0	$ 7,989.9	$ 22,982.6	$ 16,465.9	$ 11,426.4	$ 5,009.0	$ 8,587.4	$ 16,548.4	$ 115,486.4
Surplus Sales													
Energy (MWh)	100.3	13,005.8	77,811.9	101,145.3	74,690.9	11,771.5	686.0	5,642.4	47,940.5	80,359.3	52,969.8	8,371.0	474,494.9
Revenue Including Transmission Costs ($ x 1000)	$ 2.8	$ 508.8	$ 2,470.2	$ 3,189.9	$ 1,645.5	$ 275.7	$ 17.8	$ 159.7	$ 1,366.4	$ 2,582.3	$ 2,056.1	$ 371.1	$ 14,646.5
Transmission Costs ($ x 1000)	$ 0.1	$ 13.0	$ 77.8	$ 101.1	$ 74.7	$ 11.8	$ 0.7	$ 5.6	$ 47.9	$ 80.4	$ 53.0	$ 8.4	$ 474.5
Revenue Excluding Transmission Costs ($ x 1000)	$ 2.7	$ 495.8	$ 2,392.4	$ 3,088.8	$ 1,570.8	$ 263.9	$ 17.2	$ 154.1	$ 1,318.5	$ 2,502.0	$ 2,003.1	$ 362.7	$ 14,172.0
Net Power Supply Expense ($ x 1000)	$ 28,689.3	$ 15,002.0	$ 13,327.1	$ 9,575.8	$ 15,275.2	$ 19,754.0	$ 38,370.0	$ 31,884.7	$ 24,128.7	$ 16,949.5	$ 20,477.8	$ 30,614.8	$ 264,048.8

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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	453,591.9	602,749.1	615,456.9	993,073.0	998,976.2	751,788.4	534,929.4	535,880.7	389,176.9	446,172.0	410,773.2	484,003.3	7,216,570.9
Bridger													
Energy (MWh)	470,742.4	425,186.7	470,632.4	381,620.0	344,102.6	376,601.4	470,742.4	470,677.3	455,545.4	470,742.4	455,557.1	470,742.4	5,262,892.4
Cost ($ x 1000)	$ 8,722.2	$ 7,878.1	$ 8,720.3	$ 7,073.6	$ 6,389.0	$ 7,021.9	$ 8,722.2	$ 8,721.1	$ 8,440.6	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 97,574.2
Boardman													
Energy (MWh)	36,470.5	33,532.3	35,388.7	3,265.4	-	27,591.7	38,630.3	37,955.9	36,095.8	37,783.0	37,300.6	38,509.3	362,523.6
Cost ($ x 1000)	$ 610.0	$ 559.4	$ 594.5	$ 55.3	$ -	$ 477.5	$ 640.8	$ 631.2	$ 601.7	$ 628.7	$ 618.9	$ 639.1	$ 6,057.1
Valmy													
Energy (MWh)	180,348.9	162,895.8	177,416.5	137,607.2	130,891.6	152,311.0	180,346.0	180,264.6	174,508.9	180,102.7	174,503.8	180,348.9	2,011,546.0
Cost ($ x 1000)	$ 4,594.7	$ 4,150.1	$ 4,524.7	$ 3,528.5	$ 3,371.7	$ 3,911.5	$ 4,594.6	$ 4,592.7	$ 4,446.0	$ 4,588.8	$ 4,445.8	$ 4,594.7	$ 51,344.0
Danskin													
Energy (MWh)	-	-	-	-	-	-	37,313.0	19,602.6	3,218.2	1,441.1	1,180.5	1,188.7	63,944.0
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,697.3	$ 914.2	$ 153.7	$ 72.6	$ 72.5	$ 87.7	$ 2,998.0
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 2,012.6	$ 1,229.4	$ 459.7	$ 387.8	$ 378.4	$ 403.0	$ 6,715.9
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	12,130.1	9,316.0	48.1	145.3	73.8	0.0	21,713.4
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 555.8	$ 437.0	$ 2.3	$ 7.4	$ 4.6	$ 0.0	$ 1,007.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 555.8	$ 437.0	$ 2.3	$ 7.4	$ 4.6	$ 0.0	$ 1,007.1
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	205,829.5	435.8	-	-	676.1	58,729.2	285,332.3	231,384.9	183,787.3	44,058.0	106,924.3	200,322.5	1,317,479.8
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	235,883.6	23,628.9	25,715.8	27,086.1	31,482.7	122,648.4	352,968.6	292,662.3	205,797.3	75,242.2	136,667.3	237,239.8	1,767,023.0
Market Cost ($ x 1000)	$ 12,562.1	$ 22.0	$ -	$ -	$ 21.1	$ 1,934.8	$ 19,514.1	$ 10,970.3	$ 8,137.4	$ 2,094.2	$ 5,952.7	$ 12,354.7	$ 73,563.5
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 14,111.0	$ 1,222.7	$ 981.9	$ 1,034.6	$ 1,196.2	$ 5,003.1	$ 23,100.9	$ 14,195.7	$ 9,287.0	$ 3,712.7	$ 7,806.1	$ 14,648.4	$ 96,300.4
Surplus Sales													
Energy (MWh)	885.2	92,731.3	194,538.7	492,921.6	290,756.1	78,361.3	2,434.2	10,530.8	58,491.7	97,913.4	55,561.3	10,740.3	1,385,865.8
Revenue Including Transmission Costs ($ x 1000)	$ 50.0	$ 3,849.4	$ 6,474.8	$ 13,362.8	$ 7,308.4	$ 2,128.0	$ 66.3	$ 291.7	$ 1,581.5	$ 2,922.8	$ 1,986.0	$ 427.1	$ 40,448.9
Transmission Costs ($ x 1000)	$ 0.9	$ 92.7	$ 194.5	$ 492.9	$ 290.8	$ 78.4	$ 2.4	$ 10.5	$ 58.5	$ 97.9	$ 55.6	$ 10.7	$ 1,385.9
Revenue Excluding Transmission Costs ($ x 1000)	$ 49.1	$ 3,756.7	$ 6,280.2	$ 12,869.8	$ 7,017.7	$ 2,049.6	$ 63.9	$ 281.2	$ 1,523.0	$ 2,824.9	$ 1,930.5	$ 416.4	$ 39,063.1
Net Power Supply Expense ($ x 1000)	$ 28,304.0	$ 10,340.9	$ 8,856.5	$ (872.0)	$ 4,254.6	$ 14,670.4	$ 39,563.1	$ 29,525.9	$ 21,714.3	$ 15,222.7	$ 19,764.3	$ 28,591.0	$ 219,935.6

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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	461,424.8	483,893.7	633,173.3	585,819.4	759,346.2	644,679.5	514,785.4	516,984.4	378,426.9	507,421.4	409,413.6	587,638.2	6,483,006.8
Bridger													
Energy (MWh)	470,742.4	425,186.7	470,742.4	383,427.2	351,745.5	393,819.4	470,742.4	470,742.4	455,557.1	470,742.4	455,557.1	470,742.4	5,289,747.2
Cost ($ x 1000)	$ 8,722.2	$ 7,878.1	$ 8,722.2	$ 7,104.4	$ 6,519.3	$ 7,315.3	$ 8,722.2	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 98,031.9
Boardman													
Energy (MWh)	39,512.3	34,518.9	38,835.1	3,870.0	-	27,847.5	38,831.8	38,151.3	36,691.8	38,204.4	37,031.6	37,798.8	371,293.4
Cost ($ x 1000)	$ 653.4	$ 573.5	$ 643.7	$ 63.9	$ -	$ 478.3	$ 643.7	$ 634.0	$ 610.3	$ 634.7	$ 615.1	$ 628.9	$ 6,179.4
Valmy													
Energy (MWh)	180,348.9	162,666.9	180,133.1	151,075.7	145,106.1	161,865.2	180,348.9	180,348.9	174,522.0	180,348.9	174,512.2	180,348.9	2,051,625.9
Cost ($ x 1000)	$ 4,594.7	$ 4,144.6	$ 4,589.6	$ 3,850.0	$ 3,715.4	$ 4,144.1	$ 4,594.7	$ 4,594.7	$ 4,446.3	$ 4,594.7	$ 4,446.0	$ 4,594.7	$ 52,309.6
Danskin													
Energy (MWh)	9.3	-	-	439.4	8.1	37.1	39,220.9	25,389.8	5,089.1	634.5	761.2	11.6	71,601.0
Cost ($ x 1000)	$ 1.0	$ -	$ -	$ 22.3	$ 0.4	$ 1.9	$ 2,020.9	$ 1,341.6	$ 275.5	$ 36.2	$ 53.1	$ 1.0	$ 3,753.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 316.2	$ 287.3	$ 315.3	$ 328.2	$ 315.7	$ 307.8	$ 2,336.2	$ 1,656.8	$ 581.4	$ 351.5	$ 359.0	$ 316.2	$ 7,471.7
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	12,419.4	13,193.4	472.4	47.3	12.5	-	26,144.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 644.6	$ 701.2	$ 25.8	$ 2.7	$ 0.9	$ -	$ 1,375.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 644.6	$ 701.2	$ 25.8	$ 2.7	$ 0.9	$ -	$ 1,375.2
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	194,275.7	44,699.9	-	9,639.3	56,919.6	96,347.3	302,152.1	237,863.3	190,417.6	18,167.6	109,540.2	122,010.1	1,382,032.6
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.3
Total Energy Excl. CSPP (MWh)	224,329.8	67,893.0	25,715.8	36,725.4	87,726.3	160,266.5	369,788.4	299,140.8	212,427.6	49,351.8	139,283.2	158,927.4	1,831,575.9
Market Cost ($ x 1000)	$ 14,504.2	$ 2,249.1	$ -	$ 445.1	$ 2,304.5	$ 3,835.1	$ 21,637.6	$ 13,346.0	$ 9,724.0	$ 972.5	$ 6,758.2	$ 8,143.9	$ 83,920.4
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 16,053.1	$ 3,449.8	$ 981.9	$ 1,479.7	$ 3,479.6	$ 6,903.5	$ 25,224.4	$ 16,571.3	$ 10,873.7	$ 2,590.9	$ 8,611.6	$ 10,437.5	$ 106,657.2
Surplus Sales													
Energy (MWh)	215.4	18,897.7	218,528.1	111,627.1	129,235.1	35,935.6	1,511.4	8,122.3	57,288.0	133,035.6	56,076.3	34,175.0	804,647.7
Revenue Including Transmission Costs ($ x 1000)	$ 11.6	$ 864.5	$ 8,794.5	$ 4,039.1	$ 3,201.4	$ 917.0	$ 47.6	$ 251.8	$ 1,753.9	$ 4,835.7	$ 2,221.2	$ 1,529.9	$ 28,468.1
Transmission Costs ($ x 1000)	$ 0.2	$ 18.9	$ 218.5	$ 111.6	$ 129.2	$ 35.9	$ 1.5	$ 8.1	$ 57.3	$ 133.0	$ 56.1	$ 34.2	$ 804.6
Revenue Excluding Transmission Costs ($ x 1000)	$ 11.4	$ 845.6	$ 8,575.9	$ 3,927.5	$ 3,072.1	$ 881.1	$ 46.1	$ 243.6	$ 1,696.6	$ 4,702.7	$ 2,165.1	$ 1,495.7	$ 27,663.4
Net Power Supply Expense ($ x 1000)	$ 30,328.2	$ 15,487.7	$ 6,676.7	$ 8,898.7	$ 10,957.9	$ 18,268.0	$ 42,119.8	$ 32,636.6	$ 23,281.6	$ 12,194.1	$ 20,308.3	$ 23,203.9	$ 244,361.6

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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	536,054.1	847,763.8	872,501.7	947,537.0	1,154,701.4	1,159,901.3	690,712.9	591,130.1	466,218.9	501,279.8	447,374.4	744,193.1	8,959,368.6
Bridger													
Energy (MWh)	470,742.4	425,186.1	469,025.6	374,894.3	339,712.8	366,992.7	468,508.7	470,647.1	452,354.3	470,670.5	455,557.1	470,742.4	5,235,033.9
Cost ($ x 1000)	$ 8,722.2	$ 7,878.1	$ 8,692.9	$ 6,958.9	$ 6,314.2	$ 6,858.1	$ 8,684.1	$ 8,720.6	$ 8,386.2	$ 8,721.0	$ 8,440.8	$ 8,722.2	$ 97,099.4
Boardman													
Energy (MWh)	29,184.2	28,340.3	30,556.9	2,945.6	-	26,451.2	36,195.9	37,549.2	35,010.3	36,865.3	36,141.8	37,586.1	336,826.8
Cost ($ x 1000)	$ 506.0	$ 485.3	$ 525.6	$ 50.7	$ -	$ 461.2	$ 606.1	$ 625.4	$ 586.3	$ 615.6	$ 602.4	$ 625.9	$ 5,690.4
Valmy													
Energy (MWh)	178,782.9	153,362.7	168,496.0	115,790.0	106,294.5	120,446.3	177,694.9	180,150.4	163,188.8	179,692.7	174,527.4	180,323.9	1,898,750.7
Cost ($ x 1000)	$ 4,557.3	$ 3,917.8	$ 4,311.7	$ 2,995.0	$ 2,754.9	$ 3,119.1	$ 4,531.4	$ 4,590.0	$ 4,175.7	$ 4,579.0	$ 4,446.4	$ 4,594.1	$ 48,572.5
Danskin													
Energy (MWh)	-	-	-	-	-	-	12,893.6	21,411.9	360.5	296.2	852.0	0.1	35,814.2
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 514.9	$ 878.4	$ 15.1	$ 13.1	$ 45.8	$ 0.0	$ 1,467.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 830.2	$ 1,193.7	$ 321.1	$ 328.3	$ 351.8	$ 315.3	$ 5,185.2
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	3,055.7	10,337.5	6.6	18.0	1.9	-	13,419.7
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 122.9	$ 425.6	$ 0.3	$ 0.8	$ 0.1	$ -	$ 549.7
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 122.9	$ 425.6	$ 0.3	$ 0.8	$ 0.1	$ -	$ 549.7
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	138,377.3	-	-	-	29.8	683.2	188,140.2	182,019.1	130,817.1	21,423.2	87,829.9	38,254.8	787,574.5
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	168,431.4	23,193.1	25,715.8	27,086.1	30,836.4	64,602.4	255,776.5	243,296.5	152,827.1	52,607.4	117,572.9	75,172.1	1,237,117.7
Market Cost ($ x 1000)	$ 6,086.6	$ -	$ -	$ -	$ 0.8	$ 16.3	$ 8,067.9	$ 8,298.9	$ 4,877.6	$ 872.2	$ 4,193.5	$ 2,056.3	$ 34,470.1
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 7,635.5	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.9	$ 3,084.6	$ 11,654.8	$ 11,524.2	$ 6,027.2	$ 2,490.7	$ 6,046.9	$ 4,349.9	$ 57,206.9
Surplus Sales													
Energy (MWh)	7,042.8	322,584.7	436,224.5	418,522.9	416,847.9	385,814.3	20,212.5	18,694.0	64,067.8	127,714.6	71,532.5	106,725.5	2,395,984.0
Revenue Including Transmission Costs ($ x 1000)	$ 308.1	$ 10,384.3	$ 11,975.2	$ 9,870.1	$ 9,175.5	$ 9,311.9	$ 504.2	$ 480.1	$ 1,595.6	$ 3,545.2	$ 2,205.2	$ 4,099.6	$ 63,455.0
Transmission Costs ($ x 1000)	$ 7.0	$ 322.6	$ 436.2	$ 418.5	$ 416.8	$ 385.8	$ 20.2	$ 18.7	$ 64.1	$ 127.7	$ 71.5	$ 106.7	$ 2,396.0
Revenue Excluding Transmission Costs ($ x 1000)	$ 301.1	$ 10,061.8	$ 11,539.0	$ 9,451.5	$ 8,758.7	$ 8,926.1	$ 484.0	$ 461.4	$ 1,531.5	$ 3,417.5	$ 2,133.6	$ 3,992.9	$ 61,059.1
Net Power Supply Expense ($ x 1000)	$ 21,435.1	$ 3,707.5	$ 3,288.4	$ 1,893.7	$ 1,801.6	$ 4,902.9	$ 25,945.4	$ 26,618.0	$ 17,965.3	$ 13,317.9	$ 17,754.8	$ 14,614.5	$ 153,245.1

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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	694,041.1	784,865.7	917,309.2	949,264.3	1,078,379.5	594,829.4	515,949.6	523,564.9	393,064.8	453,143.7	409,727.7	491,988.7	7,806,128.5
Bridger													
Energy (MWh)	470,742.4	425,186.7	470,653.6	382,965.1	339,349.9	375,918.2	470,742.4	470,729.3	455,238.6	470,732.1	455,557.1	470,742.4	5,258,557.6
Cost ($ x 1000)	$ 8,722.2	$ 7,878.1	$ 8,720.7	$ 7,096.5	$ 6,308.0	$ 7,010.2	$ 8,722.2	$ 8,722.0	$ 8,435.4	$ 8,722.0	$ 8,440.8	$ 8,722.2	$ 97,500.4
Boardman													
Energy (MWh)	34,952.9	33,393.5	37,107.4	3,450.5	-	28,236.4	37,429.0	37,076.7	35,784.5	37,232.1	36,648.7	37,850.6	359,162.3
Cost ($ x 1000)	$ 588.3	$ 557.4	$ 619.1	$ 57.9	$ -	$ 486.7	$ 623.7	$ 618.6	$ 597.3	$ 620.8	$ 609.6	$ 629.7	$ 6,009.1
Valmy													
Energy (MWh)	180,348.9	162,648.5	171,771.7	141,328.1	125,344.3	140,898.1	180,345.1	180,317.3	174,489.0	180,220.4	174,497.6	180,348.9	1,992,558.1
Cost ($ x 1000)	$ 4,594.7	$ 4,144.2	$ 4,390.0	$ 3,617.3	$ 3,239.5	$ 3,634.7	$ 4,594.6	$ 4,594.0	$ 4,445.5	$ 4,591.6	$ 4,445.7	$ 4,594.7	$ 50,886.6
Danskin													
Energy (MWh)	-	-	-	-	-	0.2	32,153.2	18,315.9	3,397.7	556.8	1,290.5	1,359.2	57,073.4
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 0.0	$ 1,365.5	$ 797.5	$ 151.5	$ 26.2	$ 73.9	$ 93.5	$ 2,508.0
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 1,680.7	$ 1,112.7	$ 457.4	$ 341.4	$ 379.8	$ 408.7	$ 6,225.9
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	9,350.4	8,104.4	221.8	50.6	94.6	118.5	17,940.4
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 400.0	$ 354.9	$ 10.0	$ 2.4	$ 5.5	$ 8.2	$ 780.9
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 400.0	$ 354.9	$ 10.0	$ 2.4	$ 5.5	$ 8.2	$ 780.9
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	18,863.7	-	-	-	3.3	156,591.3	312,556.9	245,227.3	180,650.8	40,801.2	108,276.2	192,175.9	1,255,146.6
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	48,917.8	23,193.1	25,715.8	27,086.1	30,809.9	220,510.5	380,193.3	306,504.7	202,660.8	71,985.4	138,019.2	229,093.2	1,704,689.8
Market Cost ($ x 1000)	$ 1,018.8	$ -	$ -	$ -	$ 0.1	$ 4,749.0	$ 19,518.4	$ 10,820.0	$ 7,431.4	$ 1,783.4	$ 5,530.7	$ 10,892.7	$ 61,744.6
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 2,567.7	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.2	$ 7,817.4	$ 23,105.2	$ 14,045.3	$ 8,581.1	$ 3,401.9	$ 7,384.1	$ 13,186.4	$ 84,481.4
Surplus Sales													
Energy (MWh)	52,851.0	274,026.0	492,486.1	454,364.0	359,186.5	7,813.2	1,537.3	8,784.6	58,958.5	100,205.9	55,340.4	10,209.3	1,875,762.8
Revenue Including Transmission Costs ($ x 1000)	$ 2,676.6	$ 10,580.5	$ 15,714.9	$ 12,118.2	$ 9,166.5	$ 179.4	$ 39.7	$ 229.1	$ 1,512.8	$ 2,773.3	$ 1,777.2	$ 361.1	$ 57,129.2
Transmission Costs ($ x 1000)	$ 52.9	$ 274.0	$ 492.5	$ 454.4	$ 359.2	$ 7.8	$ 1.5	$ 8.8	$ 59.0	$ 100.2	$ 55.3	$ 10.2	$ 1,875.8
Revenue Excluding Transmission Costs ($ x 1000)	$ 2,623.8	$ 10,306.5	$ 15,222.4	$ 11,663.8	$ 8,807.3	$ 171.6	$ 38.2	$ 220.3	$ 1,453.8	$ 2,673.1	$ 1,721.8	$ 350.9	$ 55,253.5
Net Power Supply Expense ($ x 1000)	$ 14,164.4	$ 3,761.1	$ (195.4)	$ 448.4	$ 2,230.7	$ 19,083.4	$ 39,088.2	$ 29,227.2	$ 21,072.9	$ 15,007.1	$ 19,543.8	$ 27,199.0	$ 190,630.8

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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	507,566.0	840,699.0	937,373.2	868,394.9	1,013,277.4	667,409.3	516,679.9	511,150.9	394,265.7	501,116.2	406,706.9	523,160.5	7,687,799.9
Bridger													
Energy (MWh)	470,742.4	425,186.7	470,717.6	381,781.1	349,826.4	381,118.1	470,742.4	470,683.6	454,944.6	470,742.4	455,557.1	470,742.4	5,272,784.6
Cost ($ x 1000)	$ 8,722.2	$ 7,878.1	$ 8,721.8	$ 7,076.3	$ 6,486.6	$ 7,098.8	$ 8,722.2	$ 8,721.2	$ 8,430.4	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 97,742.8
Boardman													
Energy (MWh)	35,434.0	32,160.6	34,055.1	3,159.5	-	26,899.5	38,590.5	38,125.2	35,670.1	37,318.9	37,033.9	38,381.0	356,828.2
Cost ($ x 1000)	$ 595.2	$ 539.8	$ 575.5	$ 53.8	$ -	$ 464.7	$ 640.2	$ 633.6	$ 595.7	$ 622.1	$ 615.1	$ 637.2	$ 5,973.0
Valmy													
Energy (MWh)	180,284.0	162,592.1	171,886.0	137,058.4	144,592.9	155,615.2	180,196.7	180,256.0	174,379.0	180,187.1	174,531.2	180,348.9	2,021,927.5
Cost ($ x 1000)	$ 4,593.2	$ 4,142.8	$ 4,392.7	$ 3,515.5	$ 3,703.2	$ 3,992.8	$ 4,591.1	$ 4,592.5	$ 4,442.9	$ 4,590.9	$ 4,446.5	$ 4,594.7	$ 51,598.7
Danskin													
Energy (MWh)	-	-	-	-	-	-	37,160.4	26,011.8	2,056.1	485.0	1,620.1	355.5	67,688.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,687.3	$ 1,212.0	$ 98.0	$ 24.4	$ 99.3	$ 26.2	$ 3,147.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 2,002.6	$ 1,527.2	$ 404.0	$ 339.6	$ 405.3	$ 341.4	$ 6,865.1
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	12,210.0	13,711.8	62.4	16.1	14.1	1.0	26,015.4
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 558.5	$ 642.0	$ 3.0	$ 0.8	$ 0.9	$ 0.1	$ 1,205.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 558.5	$ 642.0	$ 3.0	$ 0.8	$ 0.9	$ 0.1	$ 1,205.3
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	157,013.1	-	-	-	753.8	96,646.8	302,899.7	242,155.9	180,693.2	19,655.2	109,680.1	168,714.5	1,278,212.2
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	187,067.2	23,193.1	25,715.8	27,086.1	31,560.4	160,566.0	370,536.0	303,433.3	202,703.2	50,839.4	139,423.1	205,631.8	1,727,755.4
Market Cost ($ x 1000)	$ 9,112.1	$ -	$ -	$ -	$ 25.7	$ 3,223.0	$ 21,191.5	$ 12,573.6	$ 7,787.1	$ 910.5	$ 6,028.8	$ 10,282.1	$ 71,134.4
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 10,661.0	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,200.8	$ 6,291.3	$ 24,778.4	$ 15,798.9	$ 8,936.8	$ 2,528.9	$ 7,882.2	$ 12,575.7	$ 93,871.3
Surplus Sales													
Energy (MWh)	4,941.4	328,570.0	509,676.1	367,749.9	324,560.1	39,028.6	1,490.1	7,544.0	58,182.2	126,989.7	54,391.4	17,328.8	1,840,452.5
Revenue Including Transmission Costs ($ x 1000)	$ 267.9	$ 13,029.4	$ 16,252.1	$ 10,000.8	$ 9,045.2	$ 1,017.8	$ 41.0	$ 206.4	$ 1,536.8	$ 3,941.4	$ 1,891.3	$ 687.1	$ 57,917.2
Transmission Costs ($ x 1000)	$ 4.9	$ 328.6	$ 509.7	$ 367.7	$ 324.6	$ 39.0	$ 1.5	$ 7.5	$ 58.2	$ 127.0	$ 54.4	$ 17.3	$ 1,840.5
Revenue Excluding Transmission Costs ($ x 1000)	$ 263.0	$ 12,700.8	$ 15,742.5	$ 9,633.0	$ 8,720.6	$ 978.8	$ 39.5	$ 198.9	$ 1,478.6	$ 3,814.4	$ 1,836.9	$ 669.8	$ 56,076.7
Net Power Supply Expense ($ x 1000)	$ 24,623.9	$ 1,347.9	$ (755.3)	$ 2,353.0	$ 2,985.2	$ 17,174.9	$ 41,253.4	$ 31,716.6	$ 21,334.1	$ 12,990.1	$ 19,954.0	$ 26,201.6	$ 201,179.4

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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	529,889.0	665,237.6	680,825.3	608,042.4	897,699.0	836,052.1	544,956.4	560,917.0	413,949.6	501,575.6	402,025.2	581,126.0	7,222,295.2
Bridger													
Energy (MWh)	470,742.4	425,186.7	470,621.7	383,263.4	350,796.1	381,847.0	470,742.4	470,684.5	454,787.0	470,634.4	455,557.1	470,742.4	5,275,605.1
Cost ($ x 1000)	$ 8,722.2	$ 7,878.1	$ 8,720.1	$ 7,101.6	$ 6,503.1	$ 7,111.3	$ 8,722.2	$ 8,721.2	$ 8,427.7	$ 8,720.4	$ 8,440.8	$ 8,722.2	$ 97,790.9
Boardman													
Energy (MWh)	35,340.2	33,257.1	37,979.3	3,458.7	-	27,274.3	38,427.6	37,989.4	35,483.7	35,687.1	34,711.6	33,047.7	352,656.5
Cost ($ x 1000)	$ 593.8	$ 555.5	$ 631.5	$ 58.0	$ -	$ 470.1	$ 637.9	$ 631.7	$ 593.0	$ 598.8	$ 582.0	$ 561.1	$ 5,913.4
Valmy													
Energy (MWh)	180,225.6	162,887.7	178,651.2	145,330.3	143,982.9	157,079.6	180,151.8	180,144.9	174,390.4	179,730.0	174,531.2	180,013.1	2,037,118.7
Cost ($ x 1000)	$ 4,591.8	$ 4,149.9	$ 4,554.2	$ 3,712.8	$ 3,688.7	$ 4,030.0	$ 4,590.0	$ 4,589.8	$ 4,443.1	$ 4,579.9	$ 4,446.5	$ 4,586.7	$ 51,963.4
Danskin													
Energy (MWh)	-	-	-	-	-	-	38,393.3	22,916.7	1,615.1	8.8	-	-	62,934.0
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,740.2	$ 1,065.7	$ 76.9	$ 0.4	$ -	$ -	$ 2,883.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 2,055.5	$ 1,380.9	$ 382.8	$ 315.7	$ 305.9	$ 315.3	$ 6,601.1
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	12,384.9	12,056.8	13.2	-	-	-	24,454.8
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 565.4	$ 563.5	$ 0.6	$ -	$ -	$ -	$ 1,129.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 565.4	$ 563.5	$ 0.6	$ -	$ -	$ -	$ 1,129.6
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	132,840.3	50.3	-	10,617.3	5,234.1	36,126.0	274,896.4	204,006.3	165,469.4	19,587.4	115,906.1	127,535.7	1,092,269.3
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	162,894.4	23,243.4	25,715.8	37,703.4	36,040.7	100,045.2	342,532.7	265,283.8	187,479.4	50,771.6	145,649.1	164,453.0	1,541,812.5
Market Cost ($ x 1000)	$ 7,544.2	$ 2.5	$ -	$ 379.1	$ 179.9	$ 1,173.2	$ 19,309.0	$ 10,250.4	$ 7,055.6	$ 858.3	$ 6,000.2	$ 6,651.8	$ 59,404.2
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 9,093.1	$ 1,203.2	$ 981.9	$ 1,413.7	$ 1,355.0	$ 4,241.5	$ 22,895.8	$ 13,475.7	$ 8,205.2	$ 2,476.8	$ 7,853.6	$ 8,945.5	$ 82,141.1
Surplus Sales													
Energy (MWh)	2,939.5	154,550.9	263,721.7	128,068.1	213,821.6	149,718.6	2,963.4	14,164.5	61,819.6	124,692.4	51,979.2	28,089.9	1,196,529.3
Revenue Including Transmission Costs ($ x 1000)	$ 163.7	$ 6,438.5	$ 9,291.1	$ 3,829.2	$ 6,017.3	$ 4,421.8	$ 82.7	$ 395.3	$ 1,641.2	$ 3,711.3	$ 1,646.8	$ 903.4	$ 38,542.4
Transmission Costs ($ x 1000)	$ 2.9	$ 154.6	$ 263.7	$ 128.1	$ 213.8	$ 149.7	$ 3.0	$ 14.2	$ 61.8	$ 124.7	$ 52.0	$ 28.1	$ 1,196.5
Revenue Excluding Transmission Costs ($ x 1000)	$ 160.7	$ 6,284.0	$ 9,027.4	$ 3,701.1	$ 5,803.5	$ 4,272.1	$ 79.8	$ 381.2	$ 1,579.3	$ 3,586.6	$ 1,594.9	$ 875.3	$ 37,345.9
Net Power Supply Expense ($ x 1000)	$ 23,155.4	$ 7,789.9	$ 6,175.6	$ 8,890.9	$ 6,058.6	$ 11,886.7	$ 39,387.0	$ 28,981.7	$ 20,473.2	$ 13,105.0	$ 20,034.1	$ 22,255.4	$ 208,193.6

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	544,116.6	736,482.8	636,348.4	886,845.9	928,008.6	881,345.8	575,305.9	526,551.5	478,214.1	504,609.3	409,799.4	585,731.5	7,693,359.8
Bridger													
Energy (MWh)	470,742.4	425,186.7	470,482.4	382,925.0	350,516.9	381,708.8	470,609.9	470,742.4	455,413.1	470,742.4	455,557.1	470,742.4	5,275,369.3
Cost ($ x 1000)	$ 8,722.2	$ 7,878.1	$ 8,717.8	$ 7,095.8	$ 6,498.4	$ 7,108.9	$ 8,719.9	$ 8,722.2	$ 8,438.4	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 97,786.9
Boardman													
Energy (MWh)	30,396.5	28,531.7	36,738.5	3,280.0	-	28,782.9	37,102.9	36,757.9	36,143.9	37,467.5	36,509.4	36,830.6	348,541.6
Cost ($ x 1000)	$ 523.3	$ 488.0	$ 613.8	$ 55.5	$ -	$ 494.5	$ 619.0	$ 614.1	$ 602.4	$ 624.2	$ 607.6	$ 615.1	$ 5,857.6
Valmy													
Energy (MWh)	179,483.6	161,213.5	178,452.1	138,459.7	143,663.6	155,409.7	180,205.4	180,010.6	174,531.2	180,172.2	174,531.2	180,348.9	2,026,481.8
Cost ($ x 1000)	$ 4,574.0	$ 4,109.9	$ 4,549.4	$ 3,548.9	$ 3,681.0	$ 3,985.5	$ 4,591.3	$ 4,586.6	$ 4,446.5	$ 4,590.5	$ 4,446.5	$ 4,594.7	$ 51,704.9
Danskin													
Energy (MWh)	-	-	-	-	-	-	22,284.4	15,489.2	1,896.1	765.7	1,083.0	15.9	41,534.4
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,004.5	$ 715.2	$ 89.8	$ 38.2	$ 65.9	$ 1.2	$ 1,914.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 1,319.8	$ 1,030.4	$ 395.7	$ 353.5	$ 371.9	$ 316.4	$ 5,632.6
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	2,419.2	5,083.4	186.6	158.8	34.3	-	7,882.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 109.9	$ 236.3	$ 8.9	$ 8.0	$ 2.1	$ -	$ 365.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 109.9	$ 236.3	$ 8.9	$ 8.0	$ 2.1	$ -	$ 365.1
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	125,470.9	-	7.7	-	4,315.5	23,873.2	273,918.0	249,325.5	120,226.1	19,442.5	109,907.9	122,113.1	1,048,600.4
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	155,525.0	23,193.1	25,723.5	27,086.1	35,122.1	87,792.4	341,554.3	310,602.9	142,236.1	50,626.7	139,651.0	159,030.4	1,498,143.6
Market Cost ($ x 1000)	$ 6,344.9	$ -	$ 0.3	$ -	$ 149.9	$ 731.6	$ 13,140.4	$ 10,924.0	$ 5,299.9	$ 912.6	$ 5,980.6	$ 7,046.3	$ 50,530.6
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 7,893.8	$ 1,200.7	$ 982.2	$ 1,034.6	$ 1,325.0	$ 3,799.9	$ 16,727.3	$ 14,149.4	$ 6,449.5	$ 2,531.1	$ 7,834.1	$ 9,340.0	$ 73,267.5
Surplus Sales													
Energy (MWh)	4,112.1	219,346.3	217,673.3	388,866.6	242,614.1	182,460.0	4,856.3	9,409.3	82,722.3	130,827.4	56,670.3	31,407.5	1,570,965.4
Revenue Including Transmission Costs ($ x 1000)	$ 205.5	$ 7,980.8	$ 7,383.8	$ 10,641.6	$ 6,748.2	$ 5,461.3	$ 128.1	$ 254.8	$ 2,299.2	$ 4,141.5	$ 1,968.3	$ 1,177.0	$ 48,390.2
Transmission Costs ($ x 1000)	$ 4.1	$ 219.3	$ 217.7	$ 388.9	$ 242.6	$ 182.5	$ 4.9	$ 9.4	$ 82.7	$ 130.8	$ 56.7	$ 31.4	$ 1,571.0
Revenue Excluding Transmission Costs ($ x 1000)	$ 201.4	$ 7,761.5	$ 7,166.2	$ 10,252.8	$ 6,505.6	$ 5,278.8	$ 123.2	$ 245.4	$ 2,216.4	$ 4,010.7	$ 1,911.6	$ 1,145.6	$ 46,819.2
Net Power Supply Expense ($ x 1000)	$ 21,827.2	$ 6,202.5	$ 8,012.3	$ 1,787.9	$ 5,314.1	$ 10,416.0	$ 31,963.9	$ 29,093.6	$ 18,125.0	$ 12,818.7	$ 19,791.4	$ 22,442.8	$ 187,795.4

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	789,266.8	1,017,779.9	1,121,814.9	978,042.0	1,070,848.4	1,249,388.9	894,639.2	708,467.4	621,602.2	598,075.2	532,834.3	813,313.6	10,396,072.9
Bridger													
Energy (MWh)	470,742.4	406,582.9	425,805.7	318,984.6	302,401.9	328,139.8	453,518.4	456,531.5	405,977.8	434,447.1	455,453.6	470,742.4	4,929,328.1
Cost ($ x 1000)	$ 8,722.2	$ 7,538.5	$ 7,933.8	$ 6,006.1	$ 5,678.3	$ 6,182.8	$ 8,428.6	$ 8,480.0	$ 7,595.8	$ 8,103.6	$ 8,439.1	$ 8,722.2	$ 91,831.0
Boardman													
Energy (MWh)	26,542.5	23,612.0	27,284.9	1,494.8	-	20,380.8	34,506.1	34,790.9	34,244.0	35,758.3	35,459.3	36,563.3	310,637.0
Cost ($ x 1000)	$ 468.3	$ 417.8	$ 478.9	$ 26.4	$ -	$ 361.1	$ 581.9	$ 586.0	$ 575.3	$ 599.8	$ 592.7	$ 611.3	$ 5,299.6
Valmy													
Energy (MWh)	172,653.5	115,824.5	4,340.3	-	-	-	114,823.7	120,618.8	40,991.5	107,766.3	155,642.5	179,852.7	1,012,513.8
Cost ($ x 1000)	$ 4,411.0	$ 3,016.5	$ 116.4	$ -	$ -	$ -	$ 2,985.7	$ 3,129.8	$ 1,071.6	$ 2,790.7	$ 3,995.4	$ 4,582.9	$ 26,099.8
Danskin													
Energy (MWh)	-	-	-	-	-	-	6,033.0	7,911.1	1,237.2	46.1	1,158.3	-	16,385.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 190.2	$ 255.8	$ 40.9	$ 1.6	$ 48.9	$ -	$ 537.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 505.5	$ 571.0	$ 346.9	$ 316.9	$ 354.9	$ 315.3	$ 4,255.3
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	1,325.1	5,294.2	533.1	-	79.3	-	7,231.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 42.1	$ 172.0	$ 17.8	$ -	$ 3.4	$ -	$ 235.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 42.1	$ 172.0	$ 17.8	$ -	$ 3.4	$ -	$ 235.2
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	5,075.9	426.5	9.8	-	5,567.5	4,988.2	86,581.6	153,394.0	105,032.5	6,594.7	46,127.8	14,548.8	428,347.2
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	35,129.9	23,619.6	25,725.6	27,086.1	36,374.1	68,907.4	154,218.0	214,671.4	127,042.5	37,778.9	75,870.8	51,466.1	877,890.4
Market Cost ($ x 1000)	$ 116.9	$ 11.0	$ 0.2	$ -	$ 133.4	$ 123.5	$ 2,578.5	$ 4,244.6	$ 2,944.8	$ 186.8	$ 1,788.1	$ 644.6	$ 12,772.5
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 1,665.8	$ 1,211.7	$ 982.1	$ 1,034.6	$ 1,308.5	$ 3,191.9	$ 6,165.3	$ 7,469.9	$ 4,094.5	$ 1,805.3	$ 3,641.6	$ 2,938.2	$ 35,509.3
Surplus Sales													
Energy (MWh)	118,183.0	432,157.5	474,899.9	275,877.4	194,927.3	314,237.3	34,437.7	12,456.6	25,729.5	100,156.7	96,003.1	150,645.8	2,229,712.0
Revenue Including Transmission Costs ($ x 1000)	$ 4,146.1	$ 10,572.5	$ 10,427.2	$ 4,939.5	$ 3,770.8	$ 5,504.8	$ 826.0	$ 318.1	$ 607.0	$ 2,532.4	$ 2,538.6	$ 4,718.5	$ 50,901.4
Transmission Costs ($ x 1000)	$ 118.2	$ 432.2	$ 474.9	$ 275.9	$ 194.9	$ 314.2	$ 34.4	$ 12.5	$ 25.7	$ 100.2	$ 96.0	$ 150.6	$ 2,229.7
Revenue Excluding Transmission Costs ($ x 1000)	$ 4,027.9	$ 10,140.3	$ 9,952.3	$ 4,663.7	$ 3,575.9	$ 5,190.5	$ 791.5	$ 305.6	$ 581.2	$ 2,432.2	$ 2,442.6	$ 4,567.8	$ 48,671.7
Net Power Supply Expense ($ x 1000)	$ 11,554.6	$ 2,331.5	$ (125.9)	$ 2,709.3	$ 3,726.2	$ 4,851.1	$ 17,917.6	$ 20,103.0	$ 13,120.6	$ 11,184.0	$ 14,584.3	$ 12,602.0	$ 114,558.4

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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	730,401.3	760,057.2	765,280.8	691,346.6	778,080.0	746,332.5	552,249.4	547,081.8	419,311.9	512,222.6	414,321.9	505,316.0	7,422,002.0
Bridger													
Energy (MWh)	470,742.4	425,186.7	470,742.4	383,427.2	350,722.4	382,494.3	470,742.4	470,742.4	455,517.5	470,742.4	455,557.1	470,742.4	5,277,359.5
Cost ($ x 1000)	$ 8,722.2	$ 7,878.1	$ 8,722.2	$ 7,104.4	$ 6,501.9	$ 7,122.3	$ 8,722.2	$ 8,722.2	$ 8,440.2	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 97,820.8
Boardman													
Energy (MWh)	37,763.9	33,946.4	37,966.8	3,587.0	-	27,267.4	38,375.6	38,135.9	35,969.9	37,653.4	37,195.7	38,345.6	366,207.7
Cost ($ x 1000)	$ 628.4	$ 565.3	$ 631.3	$ 59.9	$ -	$ 470.0	$ 637.2	$ 633.7	$ 599.9	$ 626.9	$ 617.4	$ 636.7	$ 6,106.8
Valmy													
Energy (MWh)	180,348.9	162,467.6	178,749.4	150,101.0	146,227.9	156,133.1	180,329.3	180,262.0	174,209.3	179,841.0	174,531.1	180,348.9	2,043,549.8
Cost ($ x 1000)	$ 4,594.7	$ 4,139.8	$ 4,556.5	$ 3,826.7	$ 3,742.2	$ 4,007.5	$ 4,594.2	$ 4,592.6	$ 4,438.8	$ 4,582.6	$ 4,446.5	$ 4,594.7	$ 52,116.9
Danskin													
Energy (MWh)	-	-	-	15.3	-	-	36,794.5	24,267.6	2,026.3	652.7	1,478.8	785.0	66,020.2
Cost ($ x 1000)	$ -	$ -	$ -	$ 0.7	$ -	$ -	$ 1,703.8	$ 1,152.5	$ 98.5	$ 33.5	$ 92.5	$ 59.0	$ 3,140.5
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 306.6	$ 315.3	$ 305.9	$ 2,019.0	$ 1,467.8	$ 404.5	$ 348.7	$ 398.4	$ 374.3	$ 6,858.3
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	12,118.3	12,010.5	29.2	39.6	7.6	11.8	24,216.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 565.2	$ 573.5	$ 1.4	$ 2.0	$ 0.5	$ 0.9	$ 1,143.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 565.2	$ 573.5	$ 1.4	$ 2.0	$ 0.5	$ 0.9	$ 1,143.6
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	8,218.9	-	-	252.1	45,743.8	49,532.0	269,712.8	214,284.3	162,645.7	16,311.9	105,587.8	181,658.2	1,053,947.4
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	38,273.0	23,193.1	25,715.8	27,338.2	76,550.4	113,451.1	337,349.1	275,561.7	184,655.7	47,496.1	135,330.8	218,575.5	1,503,490.6
Market Cost ($ x 1000)	$ 522.7	$ -	$ -	$ 10.3	$ 1,674.2	$ 1,702.7	$ 18,462.3	$ 10,905.5	$ 7,269.4	$ 782.7	$ 5,898.3	$ 11,358.4	$ 58,586.5
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 2,071.6	$ 1,200.7	$ 981.9	$ 1,044.9	$ 2,849.3	$ 4,771.1	$ 22,049.2	$ 14,130.9	$ 8,419.0	$ 2,401.2	$ 7,751.8	$ 13,652.0	$ 81,323.4
Surplus Sales													
Energy (MWh)	81,377.4	249,589.6	348,383.6	206,085.3	136,883.7	73,098.9	3,332.9	12,233.3	65,821.0	134,932.6	57,928.0	12,832.9	1,382,499.2
Revenue Including Transmission Costs ($ x 1000)	$ 4,884.9	$ 10,572.2	$ 12,445.4	$ 6,617.6	$ 3,352.2	$ 1,960.5	$ 94.8	$ 347.3	$ 1,788.7	$ 4,361.9	$ 2,113.0	$ 519.8	$ 49,058.3
Transmission Costs ($ x 1000)	$ 81.4	$ 249.6	$ 348.4	$ 206.1	$ 136.9	$ 73.1	$ 3.3	$ 12.2	$ 65.8	$ 134.9	$ 57.9	$ 12.8	$ 1,382.5
Revenue Excluding Transmission Costs ($ x 1000)	$ 4,803.5	$ 10,322.6	$ 12,097.1	$ 6,411.5	$ 3,215.3	$ 1,887.4	$ 91.5	$ 335.1	$ 1,722.9	$ 4,226.9	$ 2,055.1	$ 507.0	$ 47,675.8
Net Power Supply Expense ($ x 1000)	$ 11,528.7	$ 3,748.6	$ 3,110.2	$ 5,930.9	$ 10,193.3	$ 14,789.3	$ 38,495.5	$ 29,785.7	$ 20,581.0	$ 12,456.7	$ 19,600.4	$ 27,473.8	$ 197,694.1

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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	598,472.9	949,740.7	606,487.1	622,067.3	1,160,292.3	1,043,016.3	598,815.2	558,006.7	586,998.6	568,151.1	520,090.8	784,667.1	8,596,806.2
Bridger													
Energy (MWh)	470,742.4	425,177.6	470,742.4	383,283.9	340,445.8	375,673.4	470,334.7	470,705.1	455,458.1	470,627.6	455,557.1	470,742.4	5,259,490.5
Cost ($ x 1000)	$ 8,722.2	$ 7,878.0	$ 8,722.2	$ 7,101.9	$ 6,326.7	$ 7,006.1	$ 8,715.2	$ 8,721.6	$ 8,439.1	$ 8,720.2	$ 8,440.8	$ 8,722.2	$ 97,516.3
Boardman													
Energy (MWh)	36,758.8	32,712.4	37,564.5	3,575.8	-	26,844.5	36,688.3	37,547.2	35,618.5	37,062.4	36,306.0	36,780.4	357,458.7
Cost ($ x 1000)	$ 614.1	$ 547.7	$ 625.6	$ 59.7	$ -	$ 463.9	$ 613.1	$ 625.3	$ 594.9	$ 618.4	$ 604.7	$ 614.4	$ 5,982.0
Valmy													
Energy (MWh)	180,348.9	162,473.1	177,614.4	150,026.9	126,102.9	136,497.3	180,168.0	180,311.8	174,438.4	179,956.9	174,521.7	180,348.9	2,002,809.4
Cost ($ x 1000)	$ 4,594.7	$ 4,140.0	$ 4,529.4	$ 3,825.0	$ 3,262.3	$ 3,525.0	$ 4,590.4	$ 4,593.8	$ 4,444.3	$ 4,585.3	$ 4,446.3	$ 4,594.7	$ 51,131.3
Danskin													
Energy (MWh)	-	-	-	-	-	-	20,311.8	22,301.6	1,161.3	381.4	393.9	-	44,549.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 860.9	$ 970.6	$ 51.7	$ 17.9	$ 22.5	$ -	$ 1,923.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 1,176.2	$ 1,285.8	$ 357.6	$ 333.1	$ 328.5	$ 315.3	$ 5,641.5
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	3,114.7	10,212.8	67.3	24.4	3.9	-	13,423.0
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 133.0	$ 446.3	$ 3.0	$ 1.2	$ 0.2	$ -	$ 583.7
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 133.0	$ 446.3	$ 3.0	$ 1.2	$ 0.2	$ -	$ 583.7
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	80,457.3	-	7.1	6,258.6	250.3	3,413.4	254,488.1	212,214.0	65,241.1	6,888.6	52,048.5	23,109.5	704,376.5
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	110,511.4	23,193.1	25,722.9	33,344.7	31,056.9	67,332.6	322,124.4	273,491.4	87,251.1	38,072.8	81,791.5	60,026.8	1,153,919.7
Market Cost ($ x 1000)	$ 4,528.4	$ -	$ 0.3	$ 210.9	$ 7.8	$ 105.7	$ 12,041.8	$ 10,213.5	$ 2,705.4	$ 305.0	$ 2,723.5	$ 1,277.6	$ 34,119.8
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 6,077.3	$ 1,200.7	$ 982.2	$ 1,245.4	$ 1,182.9	$ 3,174.1	$ 15,628.7	$ 13,438.8	$ 3,855.1	$ 1,923.4	$ 4,576.9	$ 3,571.2	$ 56,856.7
Surplus Sales													
Energy (MWh)	20,682.3	438,035.5	188,059.7	142,568.5	443,200.8	296,784.4	6,931.6	16,748.0	135,094.5	180,561.5	108,169.8	131,273.4	2,108,110.0
Revenue Including Transmission Costs ($ x 1000)	$ 1,102.1	$ 15,863.8	$ 6,038.7	$ 4,102.4	$ 10,898.6	$ 8,016.9	$ 176.1	$ 465.8	$ 3,725.8	$ 5,486.1	$ 3,642.9	$ 5,256.2	$ 64,775.4
Transmission Costs ($ x 1000)	$ 20.7	$ 438.0	$ 188.1	$ 142.6	$ 443.2	$ 296.8	$ 6.9	$ 16.7	$ 135.1	$ 180.6	$ 108.2	$ 131.3	$ 2,108.1
Revenue Excluding Transmission Costs ($ x 1000)	$ 1,081.5	$ 15,425.7	$ 5,850.7	$ 3,959.8	$ 10,455.4	$ 7,720.2	$ 169.2	$ 449.1	$ 3,590.7	$ 5,305.5	$ 3,534.7	$ 5,124.9	$ 62,667.3
Net Power Supply Expense ($ x 1000)	$ 19,242.1	$ (1,372.2)	$ 9,324.0	$ 8,578.1	$ 631.8	$ 6,754.9	$ 30,687.4	$ 28,662.6	$ 14,103.4	$ 10,876.2	$ 14,862.8	$ 12,692.9	$ 155,044.0

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Hydroelectric Generation (MWh)	1,002,290.3	1,025,275.7	1,159,706.8	1,097,893.3	1,171,075.2	933,140.0	595,156.5	564,903.9	583,703.7	494,716.2	467,234.9	813,536.1	9,908,632.6
Bridger													
Energy (MWh)	470,561.2	416,061.4	465,275.4	344,590.7	312,326.1	351,786.7	466,433.1	467,805.9	436,127.8	462,769.5	455,557.1	470,727.4	5,120,022.3
Cost ($ x 1000)	$ 8,719.1	$ 7,711.3	$ 8,629.0	$ 6,442.5	$ 5,847.5	$ 6,598.9	$ 8,648.8	$ 8,672.1	$ 8,109.7	$ 8,586.3	$ 8,440.8	$ 8,721.9	$ 95,128.0
Boardman													
Energy (MWh)	26,896.4	25,864.9	29,531.8	2,718.3	-	23,059.7	34,659.0	35,917.4	34,144.2	36,575.1	33,910.9	31,183.3	314,460.8
Cost ($ x 1000)	$ 473.3	$ 450.0	$ 511.0	$ 47.5	$ -	$ 407.0	$ 584.1	$ 602.1	$ 573.9	$ 611.5	$ 570.6	$ 534.5	$ 5,365.4
Valmy													
Energy (MWh)	175,363.3	145,384.1	102,663.5	2,379.6	-	23,867.4	133,320.0	143,344.2	114,160.7	140,656.1	168,930.1	178,029.9	1,328,099.0
Cost ($ x 1000)	$ 4,475.7	$ 3,722.6	$ 2,674.4	$ 64.2	$ -	$ 628.3	$ 3,450.0	$ 3,700.1	$ 2,956.8	$ 3,638.4	$ 4,312.8	$ 4,539.3	$ 34,162.7
Danskin													
Energy (MWh)	-	-	-	-	-	-	11,872.5	14,766.7	231.6	224.0	217.1	-	27,312.0
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 406.3	$ 519.1	$ 8.3	$ 8.5	$ 10.0	$ -	$ 952.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 721.6	$ 834.3	$ 314.3	$ 323.7	$ 315.9	$ 315.3	$ 4,670.0
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	2,065.3	8,907.7	-	3.2	-	-	10,976.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 71.2	$ 314.2	$ -	$ 0.1	$ -	$ -	$ 385.5
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 71.2	$ 314.2	$ -	$ 0.1	$ -	$ -	$ 385.5
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	-	1,980.4	-	-	694.2	65,761.8	313,490.6	245,015.7	78,417.0	24,220.8	79,197.3	12,815.6	821,593.4
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	30,054.1	25,173.5	25,715.8	27,086.1	31,500.8	129,680.9	381,127.0	306,293.2	100,427.0	55,405.0	108,940.3	49,732.9	1,271,136.5
Market Cost ($ x 1000)	$ -	$ 54.8	$ -	$ -	$ 18.0	$ 1,414.4	$ 9,724.4	$ 8,680.8	$ 2,412.5	$ 819.1	$ 3,114.6	$ 562.7	$ 26,801.2
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 1,548.9	$ 1,255.5	$ 981.9	$ 1,034.6	$ 1,193.1	$ 4,482.7	$ 13,311.2	$ 11,906.1	$ 3,562.2	$ 2,437.6	$ 4,968.0	$ 2,856.3	$ 49,538.1
Surplus Sales													
Energy (MWh)	329,013.2	482,498.1	652,821.8	424,937.8	300,205.1	108,955.1	7.7	6,110.4	62,896.1	76,633.8	74,295.4	141,917.5	2,660,292.0
Revenue Including Transmission Costs ($ x 1000)	$ 11,697.8	$ 12,804.1	$ 15,240.1	$ 8,495.2	$ 5,691.6	$ 2,473.0	$ 0.2	$ 161.1	$ 1,513.2	$ 1,915.4	$ 1,973.0	$ 4,232.9	$ 66,197.4
Transmission Costs ($ x 1000)	$ 329.0	$ 482.5	$ 652.8	$ 424.9	$ 300.2	$ 109.0	$ 0.0	$ 6.1	$ 62.9	$ 76.6	$ 74.3	$ 141.9	$ 2,660.3
Revenue Excluding Transmission Costs ($ x 1000)	$ 11,368.8	$ 12,321.6	$ 14,587.2	$ 8,070.3	$ 5,391.4	$ 2,364.0	$ 0.2	$ 155.0	$ 1,450.3	$ 1,838.8	$ 1,898.7	$ 4,091.0	$ 63,537.1
Net Power Supply Expense ($ x 1000)	$ 4,163.5	$ 1,105.1	$ (1,475.6)	$ (175.6)	$ 1,964.4	$ 10,058.9	$ 26,786.7	$ 25,874.0	$ 14,066.6	$ 13,758.9	$ 16,709.4	$ 12,876.4	$ 125,712.6

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Hydroelectric Generation (MWh)	829,243.6	1,049,245.6	885,852.5	1,180,904.6	1,085,713.8	858,101.0	582,877.2	555,321.8	475,986.9	505,576.5	437,201.3	721,201.9	9,167,226.7
Bridger													
Energy (MWh)	470,549.8	416,069.1	445,182.8	340,840.4	311,347.3	352,696.6	468,456.8	468,329.1	436,108.1	452,734.9	455,397.3	470,742.4	5,088,454.5
Cost ($ x 1000)	$ 8,718.9	$ 7,722.7	$ 8,264.0	$ 6,378.6	$ 5,830.8	$ 6,614.5	$ 8,683.2	$ 8,681.1	$ 8,109.4	$ 8,415.3	$ 8,438.1	$ 8,722.2	$ 94,578.7
Boardman													
Energy (MWh)	25,434.6	21,015.2	28,196.3	2,690.0	-	24,647.8	36,142.6	36,463.9	33,927.5	31,715.3	29,957.3	34,789.9	304,980.2
Cost ($ x 1000)	$ 452.5	$ 380.8	$ 491.9	$ 47.1	$ -	$ 432.6	$ 605.3	$ 609.9	$ 570.8	$ 542.1	$ 514.1	$ 586.0	$ 5,233.0
Valmy													
Energy (MWh)	172,668.8	138,389.2	103,157.0	1,784.9	6,622.0	37,331.0	145,283.5	144,185.1	116,261.4	132,290.0	159,093.5	179,856.2	1,336,922.4
Cost ($ x 1000)	$ 4,411.3	$ 3,560.3	$ 2,678.9	$ 48.1	$ 173.9	$ 994.5	$ 3,755.8	$ 3,720.1	$ 3,012.5	$ 3,421.9	$ 4,074.2	$ 4,582.9	$ 34,434.3
Danskin													
Energy (MWh)	-	-	-	-	-	-	15,698.6	16,264.7	347.8	-	13.6	-	32,324.7
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 536.0	$ 570.7	$ 12.5	$ -	$ 0.6	$ -	$ 1,119.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 851.2	$ 886.0	$ 318.4	$ 315.3	$ 306.6	$ 315.3	$ 4,837.6
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	2,495.4	11,119.3	100.8	-	-	-	13,715.5
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 85.8	$ 391.2	$ 3.6	$ -	$ -	$ -	$ 480.7
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 85.8	$ 391.2	$ 3.6	$ -	$ -	$ -	$ 480.7
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	1,668.3	-	2,974.2	-	4,830.2	88,790.9	306,077.3	245,561.8	144,596.3	26,072.7	98,140.0	42,636.4	961,348.0
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	31,722.4	23,193.1	28,690.0	27,086.1	35,636.9	152,710.0	373,713.6	306,839.2	166,606.3	57,256.9	127,883.1	79,553.7	1,410,891.2
Market Cost ($ x 1000)	$ 33.7	$ -	$ 63.3	$ -	$ 124.5	$ 1,940.7	$ 9,822.5	$ 8,977.6	$ 4,409.2	$ 767.9	$ 3,638.8	$ 1,890.0	$ 31,668.1
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 1,582.6	$ 1,200.7	$ 1,045.2	$ 1,034.6	$ 1,299.6	$ 5,009.1	$ 13,409.3	$ 12,202.9	$ 5,558.9	$ 2,386.3	$ 5,492.2	$ 4,183.6	$ 54,405.0
Surplus Sales													
Energy (MWh)	153,467.1	492,650.7	361,006.9	503,575.8	224,622.9	72,906.8	41.9	2,694.5	23,440.0	65,858.3	49,050.9	84,851.8	2,034,167.6
Revenue Including Transmission Costs ($ x 1000)	$ 5,463.5	$ 11,970.1	$ 8,756.8	$ 10,181.7	$ 4,560.0	$ 1,663.9	$ 1.1	$ 68.0	$ 540.2	$ 1,601.1	$ 1,212.2	$ 2,428.3	$ 48,446.8
Transmission Costs ($ x 1000)	$ 153.5	$ 492.7	$ 361.0	$ 503.6	$ 224.6	$ 72.9	$ 0.0	$ 2.7	$ 23.4	$ 65.9	$ 49.1	$ 84.9	$ 2,034.2
Revenue Excluding Transmission Costs ($ x 1000)	$ 5,310.1	$ 11,477.5	$ 8,395.8	$ 9,678.1	$ 4,335.3	$ 1,591.0	$ 1.0	$ 65.3	$ 516.7	$ 1,535.2	$ 1,163.1	$ 2,343.4	$ 46,412.6
Net Power Supply Expense ($ x 1000)	$ 10,170.5	$ 1,674.2	$ 4,399.5	$ (1,863.9)	$ 3,284.2	$ 11,765.5	$ 27,389.7	$ 26,425.9	$ 17,056.9	$ 13,545.7	$ 17,662.1	$ 16,046.6	$ 147,556.8

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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	913,279.5	958,909.8	727,255.0	948,017.7	895,444.3	1,259,835.9	607,457.5	566,632.0	493,311.3	507,464.1	461,826.9	666,973.1	9,006,407.0
Bridger													
Energy (MWh)	470,689.5	420,340.9	468,855.7	372,615.9	334,777.9	342,944.4	467,028.4	469,026.3	447,452.2	470,156.9	455,557.1	470,742.4	5,190,187.6
Cost ($ x 1000)	$ 8,721.3	$ 7,795.5	$ 8,690.0	$ 6,920.1	$ 6,230.1	$ 6,411.6	$ 8,658.9	$ 8,692.9	$ 8,302.7	$ 8,712.2	$ 8,440.8	$ 8,722.2	$ 96,298.5
Boardman													
Energy (MWh)	25,942.7	22,725.1	29,749.3	2,872.9	-	3,211.9	34,943.3	35,279.6	34,620.7	36,325.7	35,572.0	37,241.9	298,485.1
Cost ($ x 1000)	$ 459.7	$ 405.2	$ 514.1	$ 49.7	$ -	$ 63.0	$ 588.2	$ 593.0	$ 580.7	$ 607.9	$ 594.3	$ 621.0	$ 5,076.7
Valmy													
Energy (MWh)	172,614.2	142,121.9	164,241.4	92,045.2	65,227.1	18,181.6	173,678.2	177,226.6	147,833.1	168,354.4	174,428.3	180,348.9	1,676,300.8
Cost ($ x 1000)	$ 4,410.1	$ 3,649.7	$ 4,205.5	$ 2,389.0	$ 1,714.4	$ 484.4	$ 4,435.4	$ 4,520.2	$ 3,809.6	$ 4,308.4	$ 4,444.0	$ 4,594.7	$ 42,965.5
Danskin													
Energy (MWh)	-	-	-	-	-	-	10,887.8	8,403.2	-	7.4	626.8	115.7	20,040.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 411.7	$ 325.4	$ -	$ 0.3	$ 31.9	$ 7.1	$ 776.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 727.0	$ 640.6	$ 305.9	$ 315.6	$ 337.8	$ 322.3	$ 4,494.2
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	1,168.7	3,138.0	-	-	-	-	4,306.7
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 44.5	$ 122.3	$ -	$ -	$ -	$ -	$ 166.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 44.5	$ 122.3	$ -	$ -	$ -	$ -	$ 166.8
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	87.7	-	-	-	29,367.7	3,471.5	265,528.5	227,127.7	114,350.1	19,749.5	79,109.5	69,171.6	807,963.9
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	30,141.8	23,193.1	25,715.8	27,086.1	60,174.3	67,390.6	333,164.8	288,405.1	136,360.1	50,933.7	108,852.5	106,088.9	1,257,507.0
Market Cost ($ x 1000)	$ 1.6	$ -	$ -	$ -	$ 723.6	$ 72.3	$ 9,248.4	$ 7,908.7	$ 3,997.0	$ 742.5	$ 3,548.3	$ 3,574.6	$ 29,817.2
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 1,550.5	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,898.8	$ 3,140.7	$ 12,835.2	$ 11,134.1	$ 5,146.6	$ 2,361.0	$ 5,401.8	$ 5,868.2	$ 52,554.1
Surplus Sales													
Energy (MWh)	236,515.6	412,029.3	285,745.6	392,907.7	140,926.5	338,984.8	3,702.9	12,282.2	53,678.7	119,527.0	76,368.6	60,218.8	2,132,887.8
Revenue Including Transmission Costs ($ x 1000)	$ 8,903.1	$ 11,186.1	$ 7,780.6	$ 9,037.3	$ 2,711.8	$ 5,511.1	$ 85.7	$ 299.9	$ 1,310.9	$ 3,215.0	$ 2,209.1	$ 1,978.7	$ 54,229.1
Transmission Costs ($ x 1000)	$ 236.5	$ 412.0	$ 285.7	$ 392.9	$ 140.9	$ 339.0	$ 3.7	$ 12.3	$ 53.7	$ 119.5	$ 76.4	$ 60.2	$ 2,132.9
Revenue Excluding Transmission Costs ($ x 1000)	$ 8,666.6	$ 10,774.1	$ 7,494.8	$ 8,644.4	$ 2,570.9	$ 5,172.1	$ 82.0	$ 287.6	$ 1,257.2	$ 3,095.4	$ 2,132.7	$ 1,918.5	$ 52,096.3
Net Power Supply Expense ($ x 1000)	$ 6,790.3	$ 2,564.3	$ 7,212.0	$ 2,054.9	$ 7,587.7	$ 5,233.6	$ 27,207.2	$ 25,415.5	$ 16,888.3	$ 13,209.6	$ 17,086.0	$ 18,210.0	$ 149,459.5

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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	651,741.4	929,383.6	1,168,060.9	1,169,315.0	1,227,031.4	706,068.3	543,753.2	535,328.8	425,221.5	506,111.2	441,345.9	679,707.4	8,983,068.7
Bridger													
Energy (MWh)	470,742.4	425,024.0	468,224.8	376,313.5	339,598.0	368,613.8	470,742.4	470,623.9	453,975.5	470,742.4	455,557.1	470,742.4	5,240,900.0
Cost ($ x 1000)	$ 8,722.2	$ 7,875.3	$ 8,679.3	$ 6,983.1	$ 6,312.3	$ 6,885.7	$ 8,722.2	$ 8,720.2	$ 8,413.9	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 97,199.4
Boardman													
Energy (MWh)	34,402.8	28,738.5	28,773.1	2,706.2	-	26,757.4	38,054.1	37,607.5	35,380.9	37,646.0	35,736.7	36,374.4	342,177.5
Cost ($ x 1000)	$ 580.5	$ 491.0	$ 500.1	$ 47.3	$ -	$ 465.6	$ 632.6	$ 626.2	$ 591.5	$ 626.8	$ 596.6	$ 608.6	$ 5,766.8
Valmy													
Energy (MWh)	179,718.3	156,039.7	160,551.2	107,804.9	88,209.9	126,928.5	176,577.2	180,307.4	168,188.6	179,978.7	174,164.7	180,348.9	1,878,818.1
Cost ($ x 1000)	$ 4,579.6	$ 3,986.4	$ 4,122.3	$ 2,793.2	$ 2,297.0	$ 3,285.0	$ 4,500.0	$ 4,593.7	$ 4,295.0	$ 4,585.9	$ 4,437.7	$ 4,594.7	$ 48,070.7
Danskin													
Energy (MWh)	-	-	-	-	-	0.2	33,054.6	20,758.1	1,524.4	924.4	272.8	-	56,534.5
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 0.0	$ 1,322.9	$ 852.1	$ 64.0	$ 40.9	$ 14.7	$ -	$ 2,294.7
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 306.0	$ 1,638.1	$ 1,167.4	$ 370.0	$ 356.2	$ 320.6	$ 315.3	$ 6,012.5
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	16,574.1	10,222.1	34.1	172.3	-	-	27,002.5
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 668.1	$ 421.7	$ 1.4	$ 7.7	$ -	$ -	$ 1,099.0
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 668.1	$ 421.7	$ 1.4	$ 7.7	$ -	$ -	$ 1,099.0
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	34,916.6	-	-	-	127.5	97,952.9	280,425.0	230,212.1	159,347.4	17,830.9	92,108.2	63,907.4	976,828.0
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	64,970.7	23,193.1	25,715.8	27,086.1	30,934.1	161,872.0	348,061.3	291,489.5	181,357.4	49,015.1	121,851.2	100,824.7	1,426,371.2
Market Cost ($ x 1000)	$ 1,740.2	$ -	$ -	$ -	$ 4.1	$ 2,721.7	$ 17,149.7	$ 10,075.0	$ 6,105.5	$ 748.9	$ 4,313.1	$ 3,349.8	$ 46,208.1
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 3,289.1	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,179.3	$ 5,790.1	$ 20,736.5	$ 13,300.3	$ 7,255.2	$ 2,367.4	$ 6,166.6	$ 5,643.4	$ 68,945.0
Surplus Sales													
Energy (MWh)	25,423.4	407,117.4	721,254.3	633,495.6	471,076.3	37,660.7	2,191.1	10,508.7	59,783.5	130,874.9	68,433.5	66,705.7	2,634,525.1
Revenue Including Transmission Costs ($ x 1000)	$ 1,124.3	$ 13,097.2	$ 18,513.9	$ 14,200.0	$ 9,177.9	$ 912.2	$ 54.1	$ 269.0	$ 1,506.0	$ 3,720.9	$ 2,036.4	$ 2,289.0	$ 66,900.9
Transmission Costs ($ x 1000)	$ 25.4	$ 407.1	$ 721.3	$ 633.5	$ 471.1	$ 37.7	$ 2.2	$ 10.5	$ 59.8	$ 130.9	$ 68.4	$ 66.7	$ 2,634.5
Revenue Excluding Transmission Costs ($ x 1000)	$ 1,098.9	$ 12,690.0	$ 17,792.6	$ 13,566.5	$ 8,706.9	$ 874.6	$ 51.9	$ 258.4	$ 1,446.3	$ 3,590.1	$ 1,967.9	$ 2,222.3	$ 64,266.3
Net Power Supply Expense ($ x 1000)	$ 16,387.8	$ 1,150.6	$ (3,193.7)	$ (2,402.3)	$ 1,396.9	$ 15,857.8	$ 36,845.6	$ 28,571.1	$ 19,480.8	$ 13,076.0	$ 17,994.5	$ 17,662.0	$ 162,827.0

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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	834,498.7	933,680.1	1,061,905.9	976,319.7	679,779.0	1,147,835.5	786,713.4	655,949.3	594,167.5	687,160.1	572,126.4	902,617.0	9,832,752.6
Bridger													
Energy (MWh)	470,733.3	396,731.1	427,057.2	336,628.6	309,688.9	309,365.1	443,920.9	460,810.0	417,270.2	452,293.7	455,391.3	470,742.4	4,950,632.8
Cost ($ x 1000)	$ 8,722.0	$ 7,370.6	$ 7,966.4	$ 6,295.5	$ 5,802.5	$ 5,825.2	$ 8,253.8	$ 8,552.9	$ 7,788.3	$ 8,407.8	$ 8,438.0	$ 8,722.2	$ 92,145.2
Boardman													
Energy (MWh)	27,212.9	19,931.9	23,987.0	2,728.4	-	10,867.3	31,657.1	34,123.1	33,336.8	33,621.7	28,539.0	29,255.8	275,261.1
Cost ($ x 1000)	$ 477.9	$ 365.3	$ 431.8	$ 47.6	$ -	$ 199.4	$ 538.4	$ 576.5	$ 562.4	$ 569.3	$ 493.9	$ 507.0	$ 4,769.4
Valmy													
Energy (MWh)	174,282.1	114,271.5	8,328.6	-	4,588.1	-	116,986.9	129,864.6	64,947.4	121,848.0	151,247.3	174,589.1	1,060,953.6
Cost ($ x 1000)	$ 4,449.9	$ 2,968.4	$ 220.3	$ -	$ 121.5	$ -	$ 3,030.0	$ 3,357.2	$ 1,689.8	$ 3,159.8	$ 3,887.9	$ 4,457.2	$ 27,341.9
Danskin													
Energy (MWh)	-	-	-	-	-	-	3,719.7	5,822.9	276.1	-	-	-	9,818.7
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 121.8	$ 195.4	$ 9.5	$ -	$ -	$ -	$ 326.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 437.1	$ 510.7	$ 315.4	$ 315.3	$ 305.9	$ 315.3	$ 4,044.6
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	364.8	4,110.5	10.0	-	-	-	4,485.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 12.0	$ 138.7	$ 0.3	$ -	$ -	$ -	$ 151.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 12.0	$ 138.7	$ 0.3	$ -	$ -	$ -	$ 151.1
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	281.4	2,576.6	160.4	366.5	211,437.1	17,979.8	180,530.8	192,715.6	107,572.3	306.6	28,699.4	4,057.9	746,684.3
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	30,335.5	25,769.7	25,876.2	27,452.6	242,243.7	81,898.9	248,167.2	253,993.0	129,582.3	31,490.8	58,442.4	40,975.2	1,196,227.5
Market Cost ($ x 1000)	$ 5.7	$ 63.0	$ 3.6	$ 7.7	$ 5,224.7	$ 337.2	$ 4,883.8	$ 5,568.2	$ 3,064.8	$ 9.0	$ 1,023.3	$ 155.6	$ 20,346.5
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 1,554.6	$ 1,263.6	$ 985.5	$ 1,042.3	$ 6,399.8	$ 3,405.6	$ 8,470.7	$ 8,793.5	$ 4,214.4	$ 1,627.5	$ 2,876.7	$ 2,449.2	$ 43,083.4
Surplus Sales													
Energy (MWh)	160,910.5	335,122.9	417,083.3	293,399.2	21,602.6	197,387.3	6,904.2	8,844.9	33,691.6	212,699.1	105,251.3	216,887.2	2,009,784.1
Revenue Including Transmission Costs ($ x 1000)	$ 5,763.3	$ 7,956.0	$ 8,804.0	$ 5,874.7	$ 364.3	$ 3,647.8	$ 162.5	$ 223.5	$ 788.9	$ 5,314.3	$ 2,630.2	$ 6,429.6	$ 47,959.1
Transmission Costs ($ x 1000)	$ 160.9	$ 335.1	$ 417.1	$ 293.4	$ 21.6	$ 197.4	$ 6.9	$ 8.8	$ 33.7	$ 212.7	$ 105.3	$ 216.9	$ 2,009.8
Revenue Excluding Transmission Costs ($ x 1000)	$ 5,602.4	$ 7,620.9	$ 8,386.9	$ 5,581.3	$ 342.7	$ 3,450.4	$ 155.6	$ 214.7	$ 755.2	$ 5,101.6	$ 2,525.0	$ 6,212.7	$ 45,949.3
Net Power Supply Expense ($ x 1000)	$ 9,917.2	$ 4,634.4	$ 1,532.3	$ 2,110.0	$ 12,296.5	$ 6,285.7	$ 20,586.3	$ 21,714.9	$ 13,815.5	$ 8,978.0	$ 13,477.5	$ 10,238.2	$ 125,586.4

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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,026,304.5	1,107,614.5	1,242,865.0	1,124,405.8	1,052,131.8	820,178.6	686,166.7	661,880.5	597,869.5	629,263.6	559,637.7	928,338.1	10,436,656.4
Bridger													
Energy (MWh)	463,137.6	343,269.6	368,311.0	270,328.5	240,616.5	298,404.3	424,643.5	405,547.7	353,974.6	405,406.6	447,296.0	470,403.0	4,491,338.8
Cost ($ x 1000)	$ 8,592.6	$ 6,448.2	$ 6,952.0	$ 5,130.8	$ 4,542.8	$ 5,635.6	$ 7,925.2	$ 7,577.2	$ 6,671.0	$ 7,608.7	$ 8,300.0	$ 8,716.4	$ 84,100.5
Boardman													
Energy (MWh)	22,249.3	13,605.7	24,238.3	1,420.1	-	20,605.1	32,020.5	33,309.1	32,934.2	31,370.2	30,461.4	32,349.3	274,563.2
Cost ($ x 1000)	$ 407.0	$ 261.3	$ 435.4	$ 25.4	$ -	$ 363.7	$ 546.5	$ 564.9	$ 556.6	$ 537.2	$ 521.3	$ 551.2	$ 4,770.5
Valmy													
Energy (MWh)	156,009.9	12,469.1	-	-	-	-	51,608.1	56,855.1	-	-	87,394.5	155,001.0	519,337.8
Cost ($ x 1000)	$ 4,014.0	$ 345.4	$ -	$ -	$ -	$ -	$ 1,374.4	$ 1,515.6	$ -	$ -	$ 2,269.2	$ 3,990.0	$ 13,508.6
Danskin													
Energy (MWh)	-	-	-	-	0.7	149.4	8,590.0	9,119.6	1,179.2	0.3	114.5	-	19,153.8
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ 0.0	$ 4.1	$ 237.2	$ 258.7	$ 34.1	$ 0.0	$ 4.2	$ -	$ 538.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 310.0	$ 552.5	$ 574.0	$ 340.1	$ 315.3	$ 310.2	$ 315.3	$ 4,256.3
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	0.6	1,636.1	7,317.8	985.0	-	-	-	9,939.5
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 0.0	$ 45.5	$ 208.1	$ 28.7	$ -	$ -	$ -	$ 282.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ 0.0	$ 45.5	$ 208.1	$ 28.7	$ -	$ -	$ -	$ 282.3
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	19.7	864.4	12.3	408.6	27,459.5	165,468.1	352,414.5	302,818.9	201,194.7	48,374.3	62,867.4	186.3	1,162,088.8
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	30,073.8	24,057.5	25,728.1	27,494.7	58,266.1	229,387.3	420,050.8	364,096.4	223,204.7	79,558.5	92,610.4	37,103.6	1,611,632.0
Market Cost ($ x 1000)	$ 0.4	$ 19.4	$ 0.3	$ 8.5	$ 491.5	$ 3,149.3	$ 8,344.2	$ 7,477.0	$ 4,972.5	$ 1,202.4	$ 1,870.9	$ 7.1	$ 27,543.4
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 1,549.3	$ 1,220.0	$ 982.2	$ 1,043.0	$ 1,666.7	$ 6,217.7	$ 11,931.0	$ 10,702.3	$ 6,122.2	$ 2,820.8	$ 3,724.3	$ 2,300.7	$ 50,280.2
Surplus Sales													
Energy (MWh)	321,622.9	345,754.9	531,070.8	373,919.0	136,318.1	16,145.9	90.0	2,297.6	4,248.4	31,884.0	57,019.4	221,903.0	2,042,274.0
Revenue Including Transmission Costs ($ x 1000)	$ 8,933.8	$ 6,798.6	$ 10,263.2	$ 6,588.0	$ 2,321.7	$ 332.0	$ 1.6	$ 56.4	$ 91.8	$ 692.4	$ 1,308.9	$ 6,261.4	$ 43,649.7
Transmission Costs ($ x 1000)	$ 321.6	$ 345.8	$ 531.1	$ 373.9	$ 136.3	$ 16.1	$ 0.1	$ 2.3	$ 4.2	$ 31.9	$ 57.0	$ 221.9	$ 2,042.3
Revenue Excluding Transmission Costs ($ x 1000)	$ 8,612.2	$ 6,452.9	$ 9,732.1	$ 6,214.1	$ 2,185.4	$ 315.9	$ 1.5	$ 54.1	$ 87.5	$ 660.5	$ 1,251.8	$ 6,039.4	$ 41,607.4
Net Power Supply Expense ($ x 1000)	$ 6,265.9	$ 2,109.3	$ (1,047.2)	$ 291.1	$ 4,339.4	$ 12,211.1	$ 22,373.6	$ 21,088.1	$ 13,631.1	$ 10,621.4	$ 13,873.2	$ 9,834.1	$ 115,591.1

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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,061,639.4	1,107,024.5	1,210,130.5	1,085,913.6	1,239,545.1	1,249,533.0	698,967.8	610,916.2	518,263.2	509,099.1	443,729.9	734,168.4	10,468,930.7
Bridger													
Energy (MWh)	470,742.4	415,961.5	459,666.4	330,197.9	293,107.6	345,774.7	462,036.5	463,389.1	427,906.8	457,829.6	455,546.7	470,742.4	5,052,901.6
Cost ($ x 1000)	$ 8,722.2	$ 7,709.6	$ 8,533.4	$ 6,197.2	$ 5,511.5	$ 6,496.5	$ 8,573.8	$ 8,596.9	$ 7,969.6	$ 8,502.1	$ 8,440.7	$ 8,722.2	$ 93,975.6
Boardman													
Energy (MWh)	28,520.8	24,082.7	30,327.8	1,464.3	-	25,705.8	35,957.4	35,493.5	34,213.8	36,809.7	35,328.3	36,397.6	324,301.8
Cost ($ x 1000)	$ 496.5	$ 424.5	$ 522.3	$ 26.2	$ -	$ 450.6	$ 602.7	$ 596.0	$ 574.9	$ 614.8	$ 590.8	$ 608.9	$ 5,508.3
Valmy													
Energy (MWh)	176,531.4	120,571.2	60,513.0	445.9	-	13,025.7	134,803.9	136,031.3	92,576.1	134,350.3	165,302.3	180,015.5	1,214,166.6
Cost ($ x 1000)	$ 4,503.5	$ 3,130.9	$ 1,577.3	$ 12.2	$ -	$ 347.3	$ 3,487.0	$ 3,516.0	$ 2,408.7	$ 3,479.5	$ 4,222.9	$ 4,586.8	$ 31,272.1
Danskin													
Energy (MWh)	-	-	-	-	-	-	14,355.3	11,574.0	1,540.9	253.7	1,952.9	29.8	29,706.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 470.2	$ 390.0	$ 52.9	$ 9.2	$ 85.8	$ 1.6	$ 1,009.7
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 785.5	$ 705.2	$ 358.9	$ 324.4	$ 391.7	$ 316.8	$ 4,727.5
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	3,253.0	6,883.1	657.5	65.4	241.1	-	11,100.1
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 107.3	$ 232.3	$ 22.8	$ 2.4	$ 10.7	$ -	$ 375.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 107.3	$ 232.3	$ 22.8	$ 2.4	$ 10.7	$ -	$ 375.4
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	-	1.7	-	-	1,035.1	936.0	211,174.6	214,788.2	131,288.1	20,577.5	88,774.9	41,563.9	710,140.0
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	30,054.1	23,194.8	25,715.8	27,086.1	31,841.7	64,855.2	278,810.9	276,065.6	153,298.1	51,761.7	118,517.9	78,481.2	1,159,683.1
Market Cost ($ x 1000)	$ -	$ 0.1	$ -	$ -	$ 26.4	$ 19.2	$ 7,047.8	$ 7,131.1	$ 3,884.9	$ 672.8	$ 3,555.5	$ 1,913.7	$ 24,251.4
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,201.5	$ 3,087.6	$ 10,634.6	$ 10,356.4	$ 5,034.6	$ 2,291.2	$ 5,408.9	$ 4,207.3	$ 46,988.3
Surplus Sales													
Energy (MWh)	391,336.0	535,573.3	656,281.9	395,377.8	349,797.4	346,314.9	3,559.0	4,524.2	22,557.7	76,454.3	60,124.1	98,542.6	2,940,443.0
Revenue Including Transmission Costs ($ x 1000)	$ 13,536.4	$ 13,176.7	$ 15,005.8	$ 7,458.6	$ 5,831.5	$ 6,766.0	$ 86.8	$ 120.0	$ 520.6	$ 1,906.6	$ 1,604.9	$ 2,984.7	$ 68,998.6
Transmission Costs ($ x 1000)	$ 391.3	$ 535.6	$ 656.3	$ 395.4	$ 349.8	$ 346.3	$ 3.6	$ 4.5	$ 22.6	$ 76.5	$ 60.1	$ 98.5	$ 2,940.4
Revenue Excluding Transmission Costs ($ x 1000)	$ 13,145.1	$ 12,641.2	$ 14,349.5	$ 7,063.3	$ 5,481.7	$ 6,419.7	$ 83.2	$ 115.5	$ 498.0	$ 1,830.1	$ 1,544.8	$ 2,886.1	$ 66,058.1
Net Power Supply Expense ($ x 1000)	$ 2,441.3	$ 111.9	$ (2,419.3)	$ 512.8	$ 1,546.6	$ 4,268.1	$ 24,107.7	$ 23,887.3	$ 15,871.4	$ 13,384.4	$ 17,520.9	$ 15,555.9	$ 116,789.1

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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	884,105.5	1,104,414.7	999,060.2	1,005,981.3	775,738.4	1,249,497.2	733,035.8	623,942.1	501,325.6	511,408.5	412,156.3	687,530.8	9,488,196.4
Bridger													
Energy (MWh)	470,574.4	421,249.4	469,012.2	364,745.0	316,073.1	351,167.8	463,002.6	467,416.0	444,496.1	465,609.5	455,554.7	470,742.4	5,159,643.5
Cost ($ x 1000)	$ 8,719.3	$ 7,811.0	$ 8,692.7	$ 6,786.0	$ 5,911.3	$ 6,588.4	$ 8,590.3	$ 8,665.5	$ 8,252.3	$ 8,634.7	$ 8,440.8	$ 8,722.2	$ 95,814.5
Boardman													
Energy (MWh)	27,553.6	21,875.0	34,048.0	3,402.2	-	20,387.0	34,677.0	35,102.6	34,303.8	36,224.5	34,743.7	35,306.1	317,623.5
Cost ($ x 1000)	$ 482.7	$ 393.0	$ 575.4	$ 57.2	$ -	$ 362.8	$ 584.4	$ 590.5	$ 576.2	$ 606.5	$ 582.4	$ 593.4	$ 5,404.4
Valmy													
Energy (MWh)	176,691.5	140,789.0	134,616.0	48,122.9	37,916.6	3,974.0	143,890.7	148,550.8	129,417.3	151,615.7	174,298.9	180,147.3	1,470,030.7
Cost ($ x 1000)	$ 4,507.4	$ 3,617.9	$ 3,489.0	$ 1,258.9	$ 986.4	$ 103.0	$ 3,720.2	$ 3,831.4	$ 3,347.9	$ 3,909.2	$ 4,440.9	$ 4,589.9	$ 37,802.2
Danskin													
Energy (MWh)	-	-	-	-	-	-	7,483.2	9,330.0	240.3	119.7	1,222.2	-	18,395.4
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 262.2	$ 335.8	$ 8.8	$ 4.6	$ 57.5	$ -	$ 669.0
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 577.5	$ 651.0	$ 314.8	$ 319.9	$ 363.5	$ 315.3	$ 4,386.8
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	1,055.7	6,428.9	-	-	62.4	-	7,547.0
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 37.3	$ 232.2	$ -	$ -	$ 3.0	$ -	$ 272.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 37.3	$ 232.2	$ -	$ -	$ 3.0	$ -	$ 272.4
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	611.2	-	-	-	108,920.1	6,626.5	182,893.3	191,779.6	114,292.6	17,936.6	108,425.4	59,180.7	790,666.1
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	30,665.2	23,193.1	25,715.8	27,086.1	139,726.7	70,545.7	250,529.6	253,057.0	136,302.6	49,120.8	138,168.5	96,098.0	1,240,209.2
Market Cost ($ x 1000)	$ 12.5	$ -	$ -	$ -	$ 2,898.2	$ 170.4	$ 5,796.3	$ 6,418.2	$ 3,689.5	$ 621.9	$ 4,370.9	$ 2,743.8	$ 26,721.7
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 1,561.4	$ 1,200.7	$ 981.9	$ 1,034.6	$ 4,073.3	$ 3,238.8	$ 9,383.1	$ 9,643.5	$ 4,839.1	$ 2,240.3	$ 6,224.3	$ 5,037.4	$ 49,458.5
Surplus Sales													
Energy (MWh)	213,438.1	556,259.8	532,380.5	399,607.4	54,757.8	342,992.2	9,049.0	7,998.8	40,187.0	100,383.5	55,711.6	68,532.4	2,381,298.3
Revenue Including Transmission Costs ($ x 1000)	$ 7,940.0	$ 13,851.3	$ 13,677.1	$ 9,047.4	$ 1,078.8	$ 5,983.0	$ 219.4	$ 204.6	$ 939.5	$ 2,567.3	$ 1,472.4	$ 2,027.0	$ 59,007.8
Transmission Costs ($ x 1000)	$ 213.4	$ 556.3	$ 532.4	$ 399.6	$ 54.8	$ 343.0	$ 9.0	$ 8.0	$ 40.2	$ 100.4	$ 55.7	$ 68.5	$ 2,381.3
Revenue Excluding Transmission Costs ($ x 1000)	$ 7,726.6	$ 13,295.0	$ 13,144.7	$ 8,647.8	$ 1,024.0	$ 5,640.0	$ 210.4	$ 196.6	$ 899.3	$ 2,466.9	$ 1,416.6	$ 1,958.5	$ 56,626.5
Net Power Supply Expense ($ x 1000)	$ 7,859.5	$ 14.9	$ 909.6	$ 794.8	$ 10,262.3	$ 4,958.9	$ 22,682.4	$ 23,417.5	$ 16,431.0	$ 13,243.7	$ 18,638.3	$ 17,299.7	$ 136,512.5

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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	737,545.4	1,051,785.2	986,421.5	1,022,413.3	859,134.5	774,701.9	605,734.2	599,450.6	433,707.8	512,825.9	412,389.3	506,654.5	8,502,764.2
Bridger													
Energy (MWh)	470,742.4	419,189.1	460,643.2	367,951.5	327,111.5	350,853.4	462,367.3	466,468.7	433,695.9	468,006.0	455,557.1	470,742.4	5,153,328.5
Cost ($ x 1000)	$ 8,722.2	$ 7,775.9	$ 8,538.8	$ 6,840.6	$ 6,099.5	$ 6,563.3	$ 8,579.5	$ 8,649.4	$ 8,068.2	$ 8,675.6	$ 8,440.8	$ 8,722.2	$ 95,675.9
Boardman													
Energy (MWh)	26,129.7	22,290.4	29,051.7	2,919.4	-	20,654.9	33,888.6	34,353.2	32,618.8	35,490.8	33,682.4	36,153.3	307,233.3
Cost ($ x 1000)	$ 462.4	$ 399.0	$ 504.1	$ 50.3	$ -	$ 369.8	$ 573.1	$ 579.8	$ 552.1	$ 596.0	$ 567.3	$ 605.5	$ 5,259.4
Valmy													
Energy (MWh)	174,726.8	142,166.2	157,365.2	87,513.3	81,580.9	81,102.3	159,869.7	173,995.5	138,200.8	164,561.5	174,344.2	180,320.7	1,715,747.2
Cost ($ x 1000)	$ 4,460.4	$ 3,650.8	$ 4,041.5	$ 2,276.0	$ 2,131.0	$ 2,122.4	$ 4,106.0	$ 4,443.1	$ 3,570.4	$ 4,218.0	$ 4,442.0	$ 4,594.0	$ 44,055.6
Danskin													
Energy (MWh)	-	-	-	-	-	-	8,758.7	5,138.3	142.4	-	33.0	248.9	14,321.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 329.1	$ 197.6	$ 5.6	$ -	$ 1.7	$ 15.1	$ 549.0
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 644.3	$ 512.8	$ 311.6	$ 315.3	$ 307.6	$ 330.3	$ 4,266.9
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	367.0	2,245.5	-	-	-	-	2,612.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 13.9	$ 87.0	$ -	$ -	$ -	$ -	$ 100.9
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 13.9	$ 87.0	$ -	$ -	$ -	$ -	$ 100.9
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	16,449.3	-	922.7	-	28,358.6	100,123.4	287,306.8	207,276.4	164,211.6	16,733.1	109,082.5	181,894.7	1,112,359.2
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	46,503.4	23,193.1	26,638.6	27,086.1	59,165.2	164,042.6	354,943.2	268,553.8	186,221.6	47,917.3	138,825.5	218,812.0	1,561,902.4
Market Cost ($ x 1000)	$ 605.1	$ -	$ 22.6	$ -	$ 734.9	$ 2,323.9	$ 9,359.1	$ 6,974.0	$ 5,266.0	$ 600.4	$ 4,591.1	$ 8,876.7	$ 39,353.8
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 2,154.0	$ 1,200.7	$ 1,004.5	$ 1,034.6	$ 1,910.1	$ 5,392.2	$ 12,945.9	$ 10,199.3	$ 6,415.7	$ 2,218.8	$ 6,444.6	$ 11,170.3	$ 62,090.7
Surplus Sales													
Energy (MWh)	79,495.5	503,362.6	530,048.6	458,153.6	112,295.0	38,775.6	1,303.0	14,377.0	18,688.6	115,086.3	54,336.6	11,639.6	1,937,561.9
Revenue Including Transmission Costs ($ x 1000)	$ 3,033.3	$ 13,288.1	$ 13,498.0	$ 10,302.4	$ 2,127.9	$ 913.7	$ 29.9	$ 347.0	$ 438.5	$ 3,094.0	$ 1,444.3	$ 336.6	$ 48,853.6
Transmission Costs ($ x 1000)	$ 79.5	$ 503.4	$ 530.0	$ 458.2	$ 112.3	$ 38.8	$ 1.3	$ 14.4	$ 18.7	$ 115.1	$ 54.3	$ 11.6	$ 1,937.6
Revenue Excluding Transmission Costs ($ x 1000)	$ 2,953.8	$ 12,784.8	$ 12,967.9	$ 9,844.2	$ 2,015.6	$ 874.9	$ 28.6	$ 332.6	$ 419.8	$ 2,978.9	$ 1,389.9	$ 324.9	$ 46,916.0
Net Power Supply Expense ($ x 1000)	$ 13,160.5	$ 528.8	$ 1,436.2	$ 663.2	$ 8,440.2	$ 13,878.8	$ 26,834.2	$ 24,138.7	$ 18,498.2	$ 13,044.7	$ 18,812.4	$ 25,097.4	$ 164,533.3

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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	609,111.8	760,381.7	623,235.1	542,292.8	803,221.8	758,536.3	563,181.2	532,270.9	463,793.9	502,825.4	409,584.8	803,194.2	7,371,629.8
Bridger													
Energy (MWh)	470,742.4	424,880.0	470,444.3	383,296.8	351,604.2	374,216.9	469,801.0	470,625.2	455,013.1	470,527.8	455,557.1	470,742.4	5,267,451.2
Cost ($ x 1000)	$ 8,722.2	$ 7,872.9	$ 8,717.1	$ 7,102.1	$ 6,516.9	$ 6,981.2	$ 8,706.2	$ 8,720.2	$ 8,431.6	$ 8,718.5	$ 8,440.8	$ 8,722.2	$ 97,651.9
Boardman													
Energy (MWh)	31,200.6	29,432.0	35,806.6	3,423.2	-	22,330.4	34,491.0	36,494.7	35,748.8	36,095.3	33,012.2	32,322.2	330,357.0
Cost ($ x 1000)	$ 534.8	$ 500.9	$ 600.5	$ 57.5	$ -	$ 393.4	$ 581.7	$ 610.3	$ 596.8	$ 604.6	$ 557.7	$ 550.8	$ 5,589.0
Valmy													
Energy (MWh)	179,972.8	161,798.6	176,924.3	145,248.0	145,070.7	147,696.6	175,437.4	179,826.0	174,531.2	180,167.9	174,265.6	179,645.5	2,020,584.5
Cost ($ x 1000)	$ 4,585.7	$ 4,123.9	$ 4,513.0	$ 3,710.8	$ 3,714.6	$ 3,796.8	$ 4,477.4	$ 4,582.2	$ 4,446.5	$ 4,590.4	$ 4,440.1	$ 4,577.9	$ 51,559.3
Danskin													
Energy (MWh)	-	-	-	-	-	-	12,081.8	14,643.6	1,130.8	-	-	-	27,856.2
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 532.8	$ 661.5	$ 52.4	$ -	$ -	$ -	$ 1,246.7
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 848.0	$ 976.8	$ 358.3	$ 315.3	$ 305.9	$ 315.3	$ 4,964.5
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	286.5	4,354.2	30.5	-	-	-	4,671.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 12.7	$ 198.0	$ 1.4	$ -	$ -	$ -	$ 212.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 12.7	$ 198.0	$ 1.4	$ -	$ -	$ -	$ 212.2
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	72,858.9	-	-	22,951.2	35,001.8	55,472.6	304,085.7	245,840.5	131,160.1	20,995.4	114,445.1	17,753.3	1,020,564.8
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	102,913.0	23,193.1	25,715.8	50,037.3	65,808.4	119,391.8	371,722.1	307,117.9	153,170.1	52,179.6	144,188.1	54,670.6	1,470,108.0
Market Cost ($ x 1000)	$ 3,767.2	$ -	$ -	$ 783.9	$ 1,243.3	$ 1,638.6	$ 12,531.2	$ 10,532.8	$ 5,611.0	$ 887.2	$ 5,499.8	$ 912.1	$ 43,407.1
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 5,316.0	$ 1,200.7	$ 981.9	$ 1,818.5	$ 2,418.4	$ 4,707.0	$ 16,118.0	$ 13,758.1	$ 6,760.7	$ 2,505.6	$ 7,353.2	$ 3,205.7	$ 66,144.0
Surplus Sales													
Energy (MWh)	17,788.5	244,423.9	202,054.4	74,568.0	151,008.1	69,592.6	2,375.3	9,503.9	77,519.5	128,080.8	56,112.8	139,282.7	1,172,310.5
Revenue Including Transmission Costs ($ x 1000)	$ 841.0	$ 8,825.9	$ 6,568.1	$ 2,101.6	$ 3,766.9	$ 1,818.5	$ 57.3	$ 246.0	$ 2,093.3	$ 3,734.7	$ 1,625.0	$ 5,413.2	$ 37,091.6
Transmission Costs ($ x 1000)	$ 17.8	$ 244.4	$ 202.1	$ 74.6	$ 151.0	$ 69.6	$ 2.4	$ 9.5	$ 77.5	$ 128.1	$ 56.1	$ 139.3	$ 1,172.3
Revenue Excluding Transmission Costs ($ x 1000)	$ 823.3	$ 8,581.5	$ 6,366.1	$ 2,027.1	$ 3,615.9	$ 1,748.9	$ 54.9	$ 236.5	$ 2,015.8	$ 3,606.6	$ 1,568.9	$ 5,273.9	$ 35,919.3
Net Power Supply Expense ($ x 1000)	$ 18,650.7	$ 5,404.1	$ 8,761.7	$ 10,967.8	$ 9,349.3	$ 14,435.5	$ 30,689.2	$ 28,609.2	$ 18,579.4	$ 13,127.8	$ 19,529.0	$ 12,097.9	$ 190,201.7

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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,162,518.6	1,097,542.6	1,160,859.9	969,038.8	1,032,921.5	1,313,533.1	625,466.9	658,469.0	622,327.2	560,872.1	519,741.4	804,025.7	10,527,316.8
Bridger													
Energy (MWh)	456,892.2	361,921.6	300,591.5	236,539.5	217,582.1	226,237.3	381,691.9	383,722.7	320,756.2	387,119.1	444,023.8	470,731.6	4,187,809.5
Cost ($ x 1000)	$ 8,486.1	$ 6,773.6	$ 5,686.9	$ 4,482.0	$ 4,133.3	$ 4,289.3	$ 7,159.4	$ 7,204.3	$ 6,041.0	$ 7,293.2	$ 8,244.3	$ 8,722.0	$ 78,515.5
Boardman													
Energy (MWh)	20,137.6	18,217.3	20,855.7	1,266.4	-	5,571.5	30,155.3	33,277.1	34,331.8	35,468.0	33,470.2	33,242.1	265,993.1
Cost ($ x 1000)	$ 370.3	$ 340.8	$ 377.8	$ 23.8	$ -	$ 104.5	$ 516.2	$ 564.4	$ 576.6	$ 595.7	$ 564.3	$ 563.9	$ 4,598.3
Valmy													
Energy (MWh)	148,686.2	360.7	-	-	-	-	38,511.6	45,980.3	5,073.8	-	76,367.0	151,771.7	466,751.4
Cost ($ x 1000)	$ 3,829.8	$ 10.2	$ -	$ -	$ -	$ -	$ 1,041.1	$ 1,248.2	$ 139.9	$ -	$ 1,997.4	$ 3,912.9	$ 12,179.5
Danskin													
Energy (MWh)	-	-	-	-	0.3	-	11,257.6	12,043.6	3,797.6	270.4	38.8	-	27,408.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ 0.0	$ -	$ 298.9	$ 328.7	$ 105.7	$ 7.9	$ 1.4	$ -	$ 742.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 614.2	$ 644.0	$ 411.6	$ 323.2	$ 307.3	$ 315.3	$ 4,460.5
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	2,574.0	8,493.7	2,203.5	10.8	-	-	13,282.0
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 68.8	$ 232.2	$ 61.7	$ 0.3	$ -	$ -	$ 363.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 68.8	$ 232.2	$ 61.7	$ 0.3	$ -	$ -	$ 363.1
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	-	1,220.2	1,936.5	15,393.4	40,893.9	16,898.3	467,332.1	333,171.5	201,500.6	105,814.7	94,545.5	19,010.4	1,297,717.1
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	30,054.1	24,413.3	27,652.3	42,479.5	71,700.5	80,817.5	534,968.4	394,448.9	223,510.6	136,998.9	124,288.5	55,927.7	1,747,260.3
Market Cost ($ x 1000)	$ -	$ 26.0	$ 41.0	$ 301.4	$ 779.2	$ 301.0	$ 10,709.6	$ 8,348.0	$ 4,850.7	$ 2,593.8	$ 2,793.6	$ 693.6	$ 31,438.0
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 1,548.9	$ 1,226.6	$ 1,022.9	$ 1,336.0	$ 1,954.3	$ 3,369.4	$ 14,296.5	$ 11,573.3	$ 6,000.3	$ 4,212.3	$ 4,647.1	$ 2,987.2	$ 54,174.8
Surplus Sales													
Energy (MWh)	442,136.6	347,194.2	379,887.8	199,594.1	107,507.3	273,579.8	-	606.7	6,101.9	7,024.2	37,434.6	114,406.6	1,915,473.8
Revenue Including Transmission Costs ($ x 1000)	$ 11,208.7	$ 6,938.9	$ 7,212.9	$ 3,333.5	$ 1,618.0	$ 4,032.3	$ -	$ 20.9	$ 146.4	$ 151.6	$ 842.1	$ 3,087.5	$ 38,592.9
Transmission Costs ($ x 1000)	$ 442.1	$ 347.2	$ 379.9	$ 199.6	$ 107.5	$ 273.6	$ -	$ 0.6	$ 6.1	$ 7.0	$ 37.4	$ 114.4	$ 1,915.5
Revenue Excluding Transmission Costs ($ x 1000)	$ 10,766.6	$ 6,591.7	$ 6,833.0	$ 3,133.9	$ 1,510.5	$ 3,758.8	$ -	$ 20.3	$ 140.3	$ 144.6	$ 804.6	$ 2,973.1	$ 36,677.4
Net Power Supply Expense ($ x 1000)	$ 3,783.8	$ 2,046.8	$ 569.8	$ 3,014.0	$ 4,892.4	$ 4,310.4	$ 23,696.3	$ 21,446.1	$ 13,090.8	$ 12,280.1	$ 14,955.7	$ 13,528.2	$ 117,614.4

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
Hoku Annualized
1957

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	879,345.7	1,093,218.5	1,089,868.5	1,146,726.8	1,246,991.1	1,254,556.4	604,240.1	575,483.4	604,586.7	559,147.1	510,945.3	743,442.0	10,308,551.5
Bridger													
Energy (MWh)	470,742.4	423,739.8	463,788.1	348,051.5	308,985.6	345,287.2	461,252.1	468,433.9	443,926.6	465,540.5	455,557.1	470,742.4	5,126,047.3
Cost ($ x 1000)	$ 8,722.2	$ 7,853.5	$ 8,603.7	$ 6,501.5	$ 5,790.5	$ 6,479.7	$ 8,549.2	$ 8,682.9	$ 8,242.6	$ 8,633.5	$ 8,440.8	$ 8,722.2	$ 95,222.2
Boardman													
Energy (MWh)	30,208.6	25,631.4	27,560.8	2,743.6	-	21,579.1	36,893.1	36,816.5	34,604.8	37,305.1	35,160.4	36,177.6	324,681.0
Cost ($ x 1000)	$ 520.6	$ 446.6	$ 482.8	$ 47.8	$ -	$ 385.9	$ 616.0	$ 614.9	$ 580.5	$ 621.9	$ 588.4	$ 605.8	$ 5,511.3
Valmy													
Energy (MWh)	178,951.0	143,723.6	100,818.1	16,533.6	6,521.4	8,134.6	145,308.3	150,333.5	128,807.3	148,727.3	172,062.7	180,292.5	1,380,213.9
Cost ($ x 1000)	$ 4,561.3	$ 3,687.8	$ 2,620.3	$ 440.3	$ 174.4	$ 212.9	$ 3,746.1	$ 3,869.1	$ 3,333.9	$ 3,839.2	$ 4,383.9	$ 4,593.4	$ 35,462.7
Danskin													
Energy (MWh)	-	-	-	-	-	-	22,327.4	20,453.2	619.8	253.3	679.3	-	44,332.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 778.7	$ 733.3	$ 22.7	$ 9.8	$ 31.8	$ -	$ 1,576.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 1,094.0	$ 1,048.5	$ 328.6	$ 325.0	$ 337.8	$ 315.3	$ 5,294.1
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	8,112.3	15,868.9	215.2	32.8	24.9	-	24,254.0
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 285.0	$ 570.4	$ 7.9	$ 1.3	$ 1.2	$ -	$ 865.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 285.0	$ 570.4	$ 7.9	$ 1.3	$ 1.2	$ -	$ 865.8
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	49.9	-	-	-	1,061.4	1,101.9	279,227.3	216,306.4	60,938.3	7,885.7	54,765.1	33,222.5	654,558.6
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	30,104.0	23,193.1	25,715.8	27,086.1	31,868.0	65,021.1	346,863.6	277,583.8	82,948.3	39,069.9	84,508.1	70,139.8	1,104,101.8
Market Cost ($ x 1000)	$ 1.0	$ -	$ -	$ -	$ 27.0	$ 22.2	$ 11,727.1	$ 8,715.1	$ 1,981.2	$ 284.7	$ 2,266.5	$ 1,602.0	$ 26,626.8
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 1,549.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,202.1	$ 3,090.6	$ 15,313.9	$ 11,940.5	$ 3,130.9	$ 1,903.2	$ 4,120.0	$ 3,895.6	$ 49,363.6
Surplus Sales													
Energy (MWh)	213,199.6	554,245.1	577,679.6	491,411.5	379,669.1	341,998.8	371.2	9,144.6	89,809.9	136,360.8	98,442.9	99,502.1	2,991,835.0
Revenue Including Transmission Costs ($ x 1000)	$ 8,377.9	$ 14,618.9	$ 13,369.1	$ 10,374.0	$ 6,423.8	$ 6,504.7	$ 8.5	$ 250.7	$ 2,199.6	$ 3,624.9	$ 2,689.6	$ 3,157.6	$ 71,599.4
Transmission Costs ($ x 1000)	$ 213.2	$ 554.2	$ 577.7	$ 491.4	$ 379.7	$ 342.0	$ 0.4	$ 9.1	$ 89.8	$ 136.4	$ 98.4	$ 99.5	$ 2,991.8
Revenue Excluding Transmission Costs ($ x 1000)	$ 8,164.7	$ 14,064.7	$ 12,791.4	$ 9,882.6	$ 6,044.2	$ 6,162.7	$ 8.1	$ 241.5	$ 2,109.8	$ 3,488.6	$ 2,591.1	$ 3,058.1	$ 68,607.6
Net Power Supply Expense ($ x 1000)	$ 7,504.5	$ (588.8)	$ 212.6	$ (1,552.5)	$ 1,438.1	$ 4,312.4	$ 29,596.1	$ 26,484.7	$ 13,514.6	$ 11,835.5	$ 15,280.9	$ 15,074.1	$ 123,112.2

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
Hoku Annualized
1958

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	755,916.0	1,119,303.5	993,395.2	1,011,738.6	1,251,177.0	1,041,654.3	598,957.3	591,865.9	485,078.0	509,170.2	410,024.1	650,993.7	9,419,273.9
Bridger													
Energy (MWh)	470,742.4	422,259.2	466,750.7	354,254.5	308,731.8	359,231.8	461,239.1	467,534.6	442,225.2	464,251.9	455,545.9	470,742.4	5,143,509.3
Cost ($ x 1000)	$ 8,722.2	$ 7,828.2	$ 8,654.2	$ 6,607.2	$ 5,786.2	$ 6,725.8	$ 8,548.9	$ 8,667.5	$ 8,213.6	$ 8,611.6	$ 8,440.6	$ 8,722.2	$ 95,528.3
Boardman													
Energy (MWh)	29,955.4	22,690.5	29,377.1	2,863.0	-	26,241.8	37,416.0	36,214.6	34,592.0	36,568.6	32,803.2	33,297.0	322,019.3
Cost ($ x 1000)	$ 517.0	$ 404.7	$ 508.7	$ 49.5	$ -	$ 458.2	$ 623.5	$ 606.3	$ 580.3	$ 611.4	$ 554.8	$ 564.7	$ 5,479.1
Valmy													
Energy (MWh)	178,683.2	142,314.6	122,340.6	26,366.2	7,012.6	26,958.6	148,976.4	148,883.4	129,279.4	148,318.9	171,501.7	179,738.1	1,430,373.7
Cost ($ x 1000)	$ 4,554.9	$ 3,654.3	$ 3,181.3	$ 694.7	$ 186.5	$ 704.0	$ 3,838.4	$ 3,834.5	$ 3,343.4	$ 3,829.2	$ 4,370.7	$ 4,580.1	$ 36,772.2
Danskin													
Energy (MWh)	-	-	-	-	-	-	26,806.2	15,742.9	633.5	117.5	11.3	-	43,311.4
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 932.8	$ 563.0	$ 23.1	$ 4.5	$ 0.5	$ -	$ 1,524.0
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 1,248.1	$ 878.2	$ 329.1	$ 319.8	$ 306.5	$ 315.3	$ 5,241.8
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	10,757.8	11,167.3	21.7	-	-	-	21,946.7
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 377.0	$ 400.5	$ 0.8	$ -	$ -	$ -	$ 778.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 377.0	$ 400.5	$ 0.8	$ -	$ -	$ -	$ 778.3
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	5,214.2	-	-	-	484.4	13,155.3	273,855.0	209,464.5	126,133.6	19,050.8	113,185.0	78,438.0	838,981.0
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	35,268.3	23,193.1	25,715.8	27,086.1	31,291.0	77,074.5	341,491.4	270,742.0	148,143.6	50,235.0	142,928.0	115,355.3	1,288,524.2
Market Cost ($ x 1000)	$ 174.6	$ -	$ -	$ -	$ 11.8	$ 301.1	$ 13,145.3	$ 7,915.6	$ 3,977.3	$ 658.6	$ 4,342.4	$ 3,414.2	$ 33,940.9
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 1,723.5	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,187.0	$ 3,369.5	$ 16,732.1	$ 11,140.9	$ 5,127.0	$ 2,277.0	$ 6,195.8	$ 5,707.8	$ 56,677.8
Surplus Sales													
Energy (MWh)	94,413.1	574,499.5	507,507.8	372,578.3	383,515.2	178,581.4	1,018.4	6,322.1	34,074.7	94,946.9	52,319.3	48,834.3	2,348,611.1
Revenue Including Transmission Costs ($ x 1000)	$ 3,624.0	$ 14,408.5	$ 12,374.0	$ 8,033.6	$ 6,362.0	$ 3,984.1	$ 25.1	$ 165.4	$ 794.2	$ 2,445.7	$ 1,326.4	$ 1,295.8	$ 54,838.8
Transmission Costs ($ x 1000)	$ 94.4	$ 574.5	$ 507.5	$ 372.6	$ 383.5	$ 178.6	$ 1.0	$ 6.3	$ 34.1	$ 94.9	$ 52.3	$ 48.8	$ 2,348.6
Revenue Excluding Transmission Costs ($ x 1000)	$ 3,529.6	$ 13,834.0	$ 11,866.5	$ 7,661.0	$ 5,978.5	$ 3,805.5	$ 24.1	$ 159.1	$ 760.1	$ 2,350.7	$ 1,274.1	$ 1,246.9	$ 52,490.2
Net Power Supply Expense ($ x 1000)	$ 12,303.3	$ (458.9)	$ 1,774.9	$ 1,030.9	$ 1,496.4	$ 7,758.1	$ 31,344.0	$ 25,368.9	$ 16,834.0	$ 13,298.3	$ 18,594.2	$ 18,643.1	$ 147,987.3

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
Hoku Annualized
1959

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	657,655.7	885,147.4	730,790.5	786,615.8	695,926.1	758,236.4	546,620.0	555,873.6	494,749.4	512,748.5	407,636.0	642,084.5	7,674,083.9
Bridger													
Energy (MWh)	470,742.4	419,954.4	469,238.5	376,531.8	333,696.2	379,354.0	470,367.2	470,023.0	441,036.3	466,135.8	455,557.1	470,742.4	5,223,379.1
Cost ($ x 1000)	$ 8,722.2	$ 7,788.9	$ 8,696.6	$ 6,986.8	$ 6,211.7	$ 7,068.8	$ 8,715.8	$ 8,709.9	$ 8,193.4	$ 8,643.7	$ 8,440.8	$ 8,722.2	$ 96,900.8
Boardman													
Energy (MWh)	25,039.7	23,480.5	30,560.8	2,929.0	-	17,949.7	35,259.9	36,559.8	32,897.5	32,659.1	31,056.2	34,802.9	303,195.1
Cost ($ x 1000)	$ 444.0	$ 415.9	$ 525.6	$ 50.5	$ -	$ 327.7	$ 592.7	$ 611.3	$ 556.1	$ 555.6	$ 529.8	$ 586.2	$ 5,195.4
Valmy													
Energy (MWh)	172,919.4	144,013.4	167,342.7	131,391.8	126,554.9	120,340.9	175,732.7	180,126.3	171,808.0	172,736.2	173,358.0	180,042.7	1,916,366.9
Cost ($ x 1000)	$ 4,417.3	$ 3,694.8	$ 4,284.3	$ 3,380.3	$ 3,270.8	$ 3,125.4	$ 4,484.5	$ 4,589.4	$ 4,381.5	$ 4,413.0	$ 4,418.5	$ 4,587.4	$ 49,047.0
Danskin													
Energy (MWh)	-	-	-	-	-	-	14,960.1	15,198.4	-	-	-	-	30,158.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 635.3	$ 662.7	$ -	$ -	$ -	$ -	$ 1,298.0
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 950.6	$ 978.0	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 5,015.9
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	557.9	6,817.0	-	-	-	-	7,374.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 23.9	$ 298.5	$ -	$ -	$ -	$ -	$ 322.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 23.9	$ 298.5	$ -	$ -	$ -	$ -	$ 322.4
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	43,847.0	51.3	-	0.3	94,569.4	63,275.2	315,645.3	222,736.6	112,923.6	17,463.1	115,125.1	85,420.3	1,071,057.2
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	73,901.1	23,244.4	25,715.8	27,086.4	125,376.0	127,194.4	383,281.6	284,014.1	134,933.6	48,647.3	144,868.1	122,337.6	1,520,600.4
Market Cost ($ x 1000)	$ 1,735.5	$ 1.0	$ -	$ 0.0	$ 2,919.2	$ 1,769.4	$ 12,899.4	$ 9,792.3	$ 4,240.4	$ 662.9	$ 5,219.2	$ 4,463.7	$ 43,702.9
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 3,284.4	$ 1,201.7	$ 981.9	$ 1,034.6	$ 4,094.4	$ 4,837.7	$ 16,486.2	$ 13,017.6	$ 5,390.1	$ 2,281.4	$ 7,072.6	$ 6,757.3	$ 66,439.8
Surplus Sales													
Energy (MWh)	24,106.1	340,578.6	293,576.7	274,824.6	66,856.1	50,495.9	2,153.8	12,783.7	69,526.1	119,211.6	51,980.4	48,717.8	1,354,811.4
Revenue Including Transmission Costs ($ x 1000)	$ 952.2	$ 10,002.4	$ 8,533.9	$ 7,132.5	$ 1,378.6	$ 1,245.1	$ 51.8	$ 327.1	$ 1,692.5	$ 3,206.1	$ 1,352.6	$ 1,609.5	$ 37,484.2
Transmission Costs ($ x 1000)	$ 24.1	$ 340.6	$ 293.6	$ 274.8	$ 66.9	$ 50.5	$ 2.2	$ 12.8	$ 69.5	$ 119.2	$ 52.0	$ 48.7	$ 1,354.8
Revenue Excluding Transmission Costs ($ x 1000)	$ 928.1	$ 9,661.8	$ 8,240.3	$ 6,857.7	$ 1,311.7	$ 1,194.6	$ 49.6	$ 314.3	$ 1,623.0	$ 3,086.8	$ 1,300.6	$ 1,560.8	$ 36,129.4
Net Power Supply Expense ($ x 1000)	$ 16,255.0	$ 3,726.9	$ 6,563.3	$ 4,900.4	$ 12,580.4	$ 14,471.0	$ 31,203.9	$ 27,890.3	$ 17,204.0	$ 13,122.0	$ 19,467.1	$ 19,407.5	$ 186,791.8

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	600,578.3	820,017.3	914,391.4	839,973.5	828,472.0	822,738.2	528,291.1	557,809.0	415,790.2	505,595.4	407,800.5	493,782.1	7,735,239.2
Bridger													
Energy (MWh)	470,742.4	424,990.0	469,228.3	376,639.7	347,432.6	378,863.6	470,709.4	470,704.3	455,100.6	470,742.4	455,557.1	470,742.4	5,261,452.9
Cost ($ x 1000)	$ 8,722.2	$ 7,874.8	$ 8,696.4	$ 6,988.7	$ 6,445.8	$ 7,060.4	$ 8,721.6	$ 8,721.5	$ 8,433.1	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 97,549.7
Boardman													
Energy (MWh)	29,833.5	25,683.4	29,061.0	2,678.8	-	23,660.1	36,282.7	36,814.7	35,512.6	37,150.3	35,601.6	37,731.5	330,010.2
Cost ($ x 1000)	$ 515.3	$ 447.4	$ 504.2	$ 46.9	$ -	$ 412.5	$ 607.3	$ 614.9	$ 593.4	$ 619.7	$ 594.7	$ 628.0	$ 5,584.2
Valmy													
Energy (MWh)	179,227.9	157,149.5	161,998.7	125,688.1	139,779.8	150,363.0	178,419.6	180,058.2	174,234.3	180,231.0	174,531.2	180,294.3	1,981,975.7
Cost ($ x 1000)	$ 4,567.9	$ 4,012.9	$ 4,156.9	$ 3,241.8	$ 3,588.5	$ 3,860.4	$ 4,548.6	$ 4,587.8	$ 4,439.4	$ 4,591.9	$ 4,446.5	$ 4,593.4	$ 50,636.0
Danskin													
Energy (MWh)	-	-	-	-	-	-	18,685.1	14,798.2	776.1	642.3	328.7	1,051.2	36,281.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 822.5	$ 667.6	$ 35.9	$ 31.3	$ 19.5	$ 75.0	$ 1,651.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 1,137.7	$ 982.9	$ 341.8	$ 346.6	$ 325.5	$ 390.3	$ 5,369.7
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	1,195.6	5,247.8	-	55.9	29.3	81.2	6,609.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 53.0	$ 238.2	$ -	$ 2.7	$ 1.8	$ 5.8	$ 301.5
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 53.0	$ 238.2	$ -	$ 2.7	$ 1.8	$ 5.8	$ 301.5
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	79,076.3	-	-	-	27,314.5	35,011.8	325,353.8	221,676.3	166,164.5	17,924.9	110,564.1	191,317.2	1,174,403.3
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	109,130.3	23,193.1	25,715.8	27,086.1	58,121.1	98,931.0	392,990.1	282,953.8	188,174.4	49,109.1	140,307.1	228,234.5	1,623,946.5
Market Cost ($ x 1000)	$ 3,964.0	$ -	$ -	$ -	$ 955.9	$ 1,067.9	$ 15,316.8	$ 9,725.5	$ 6,936.8	$ 803.9	$ 5,660.7	$ 11,070.5	$ 55,502.0
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 5,512.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 2,131.0	$ 4,136.3	$ 18,903.6	$ 12,950.9	$ 8,086.4	$ 2,422.3	$ 7,514.1	$ 13,364.1	$ 78,238.9
Surplus Sales													
Energy (MWh)	13,360.4	295,772.0	470,323.7	322,336.1	159,108.4	121,976.4	1,948.0	12,557.4	63,689.4	129,811.2	53,660.5	10,625.0	1,655,168.5
Revenue Including Transmission Costs ($ x 1000)	$ 607.4	$ 9,840.0	$ 13,484.1	$ 7,887.8	$ 3,912.6	$ 3,403.0	$ 49.6	$ 333.2	$ 1,674.6	$ 3,959.2	$ 1,709.6	$ 387.4	$ 47,248.4
Transmission Costs ($ x 1000)	$ 13.4	$ 295.8	$ 470.3	$ 322.3	$ 159.1	$ 122.0	$ 1.9	$ 12.6	$ 63.7	$ 129.8	$ 53.7	$ 10.6	$ 1,655.2
Revenue Excluding Transmission Costs ($ x 1000)	$ 594.0	$ 9,544.2	$ 13,013.8	$ 7,565.4	$ 3,753.5	$ 3,281.0	$ 47.6	$ 320.6	$ 1,610.9	$ 3,829.4	$ 1,655.9	$ 376.8	$ 45,593.3
Net Power Supply Expense ($ x 1000)	$ 19,039.5	$ 4,278.8	$ 1,641.0	$ 4,052.5	$ 8,727.1	$ 12,494.5	$ 33,924.3	$ 27,775.5	$ 20,283.2	$ 12,876.0	$ 19,667.4	$ 27,327.0	$ 192,086.8

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	476,678.8	679,938.3	618,776.3	495,841.8	735,106.5	719,516.6	495,987.2	508,743.1	373,217.6	472,622.1	405,402.4	504,029.6	6,485,860.3
Bridger													
Energy (MWh)	470,742.4	424,971.6	470,325.8	382,541.3	344,553.7	394,272.9	470,631.9	470,742.4	455,526.6	470,742.4	455,557.1	470,742.4	5,281,350.4
Cost ($ x 1000)	$ 8,722.2	$ 7,874.4	$ 8,715.1	$ 7,089.3	$ 6,396.7	$ 7,323.0	$ 8,720.3	$ 8,722.2	$ 8,440.3	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 97,888.8
Boardman													
Energy (MWh)	29,076.3	22,695.6	29,877.7	3,068.5	-	13,276.9	37,184.5	37,489.4	36,276.9	37,152.2	37,172.3	38,133.4	321,403.6
Cost ($ x 1000)	$ 504.5	$ 404.7	$ 515.9	$ 52.5	$ -	$ 244.9	$ 620.2	$ 624.5	$ 604.3	$ 619.7	$ 617.1	$ 633.7	$ 5,442.0
Valmy													
Energy (MWh)	179,441.7	149,722.1	170,645.2	139,329.6	138,264.5	154,941.1	178,975.6	180,307.4	174,531.2	180,217.1	174,531.2	180,348.9	2,001,255.6
Cost ($ x 1000)	$ 4,573.0	$ 3,835.5	$ 4,363.1	$ 3,569.6	$ 3,552.3	$ 3,979.0	$ 4,561.9	$ 4,593.7	$ 4,446.5	$ 4,591.6	$ 4,446.5	$ 4,594.7	$ 51,107.4
Danskin													
Energy (MWh)	-	-	-	-	-	-	23,903.7	20,952.0	5,750.7	356.1	1,761.8	469.1	53,193.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,136.1	$ 1,021.1	$ 287.1	$ 18.7	$ 113.1	$ 36.2	$ 2,612.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 1,451.3	$ 1,336.4	$ 593.0	$ 334.0	$ 419.1	$ 351.5	$ 6,330.2
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	2,581.1	8,359.3	609.1	-	122.0	-	11,671.4
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 123.6	$ 409.7	$ 30.6	$ -	$ 7.9	$ -	$ 571.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 123.6	$ 409.7	$ 30.6	$ -	$ 7.9	$ -	$ 571.8
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	192,003.0	326.2	34.6	47,214.5	66,611.2	61,273.8	348,612.4	255,077.7	192,056.3	32,457.9	110,780.6	184,531.8	1,490,980.0
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	222,057.1	23,519.3	25,750.4	74,300.7	97,417.8	125,193.0	416,248.8	316,355.1	214,066.3	63,642.1	140,523.6	221,449.1	1,940,523.2
Market Cost ($ x 1000)	$ 10,143.3	$ 7.0	$ 1.2	$ 1,626.3	$ 2,358.9	$ 2,072.4	$ 19,173.1	$ 12,590.4	$ 9,077.7	$ 1,556.9	$ 6,400.8	$ 11,658.0	$ 76,666.0
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 11,692.2	$ 1,207.7	$ 983.2	$ 2,660.8	$ 3,534.0	$ 5,140.7	$ 22,760.0	$ 15,815.7	$ 10,227.4	$ 3,175.4	$ 8,254.3	$ 13,951.6	$ 99,402.9
Surplus Sales													
Energy (MWh)	1,844.1	145,585.4	185,303.7	45,351.8	100,645.4	54,621.0	887.0	7,120.1	54,079.6	111,016.7	54,575.4	13,880.3	774,910.4
Revenue Including Transmission Costs ($ x 1000)	$ 80.6	$ 4,887.6	$ 5,696.0	$ 1,243.8	$ 2,230.0	$ 1,328.5	$ 23.6	$ 198.5	$ 1,518.2	$ 3,455.3	$ 2,033.5	$ 570.1	$ 23,265.5
Transmission Costs ($ x 1000)	$ 1.8	$ 145.6	$ 185.3	$ 45.4	$ 100.6	$ 54.6	$ 0.9	$ 7.1	$ 54.1	$ 111.0	$ 54.6	$ 13.9	$ 774.9
Revenue Excluding Transmission Costs ($ x 1000)	$ 78.7	$ 4,742.0	$ 5,510.7	$ 1,198.4	$ 2,129.3	$ 1,273.8	$ 22.7	$ 191.3	$ 1,464.1	$ 3,344.3	$ 1,978.9	$ 556.2	$ 22,490.6
Net Power Supply Expense ($ x 1000)	$ 25,728.4	$ 8,867.7	$ 9,381.8	$ 12,479.7	$ 11,669.0	$ 15,719.8	$ 38,214.5	$ 31,310.9	$ 22,878.0	$ 14,098.6	$ 20,206.8	$ 27,697.4	$ 238,252.7

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
Hoku Annualized
1962

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	471,714.6	754,942.9	587,598.7	1,128,176.1	1,025,190.4	778,945.6	562,518.2	555,948.8	507,538.7	508,869.4	407,558.9	739,759.7	8,028,761.8
Bridger													
Energy (MWh)	470,742.4	425,135.0	470,272.6	375,916.9	339,270.5	372,743.5	470,491.0	470,487.3	453,703.8	469,819.9	455,557.1	470,742.4	5,244,882.3
Cost ($ x 1000)	$ 8,722.2	$ 7,877.2	$ 8,714.2	$ 6,976.4	$ 6,306.7	$ 6,956.1	$ 8,717.9	$ 8,717.8	$ 8,409.2	$ 8,706.5	$ 8,440.8	$ 8,722.2	$ 97,267.3
Boardman													
Energy (MWh)	30,530.7	27,812.5	33,857.7	2,987.2	-	26,224.4	36,832.2	36,151.4	35,120.5	36,193.0	33,394.4	34,275.1	333,379.1
Cost ($ x 1000)	$ 525.2	$ 477.8	$ 572.7	$ 51.3	$ -	$ 455.1	$ 615.1	$ 605.4	$ 587.8	$ 606.0	$ 563.2	$ 578.6	$ 5,638.3
Valmy													
Energy (MWh)	179,657.0	156,120.0	174,511.8	109,369.2	118,913.1	126,011.7	179,342.4	179,946.2	165,465.1	179,307.0	174,435.9	180,348.9	1,923,428.5
Cost ($ x 1000)	$ 4,578.2	$ 3,988.3	$ 4,455.3	$ 2,833.1	$ 3,073.2	$ 3,261.1	$ 4,570.7	$ 4,585.1	$ 4,230.0	$ 4,569.8	$ 4,444.2	$ 4,594.7	$ 49,183.8
Danskin													
Energy (MWh)	-	-	-	-	-	148.0	21,160.2	12,175.4	502.3	4.8	-	-	33,990.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 5.8	$ 843.3	$ 497.3	$ 21.0	$ 0.2	$ -	$ -	$ 1,367.7
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 311.8	$ 1,158.6	$ 812.6	$ 327.0	$ 315.5	$ 305.9	$ 315.3	$ 5,085.6
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	1.3	5,406.4	7,306.1	11.8	-	-	-	12,725.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 0.0	$ 217.0	$ 300.2	$ 0.5	$ -	$ -	$ -	$ 517.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ 0.0	$ 217.0	$ 300.2	$ 0.5	$ -	$ -	$ -	$ 517.8
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	196,739.4	1.8	5,179.9	-	2,333.1	60,609.5	284,511.8	225,817.5	104,022.3	18,641.0	113,891.1	42,640.4	1,054,387.8
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	226,793.5	23,194.9	30,895.8	27,086.1	33,139.7	124,528.6	352,148.1	287,095.0	126,032.3	49,825.2	143,634.1	79,557.7	1,503,931.0
Market Cost ($ x 1000)	$ 9,338.6	$ 0.0	$ 188.8	$ -	$ 68.9	$ 1,700.8	$ 12,822.9	$ 8,772.6	$ 4,010.4	$ 711.4	$ 5,041.9	$ 2,054.8	$ 44,711.2
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 10,887.5	$ 1,200.7	$ 1,170.8	$ 1,034.6	$ 1,244.0	$ 4,769.1	$ 16,409.7	$ 11,997.9	$ 5,160.1	$ 2,329.9	$ 6,895.4	$ 4,348.4	$ 67,448.0
Surplus Sales													
Energy (MWh)	3,286.2	231,943.9	167,065.0	593,805.3	301,816.6	76,023.5	3,272.7	13,281.5	82,475.7	130,304.0	54,085.4	103,391.6	1,760,751.3
Revenue Including Transmission Costs ($ x 1000)	$ 136.2	$ 7,459.1	$ 4,789.3	$ 13,170.9	$ 7,268.6	$ 1,964.2	$ 79.0	$ 343.7	$ 2,088.4	$ 3,557.1	$ 1,479.6	$ 3,649.6	$ 45,985.7
Transmission Costs ($ x 1000)	$ 3.3	$ 231.9	$ 167.1	$ 593.8	$ 301.8	$ 76.0	$ 3.3	$ 13.3	$ 82.5	$ 130.3	$ 54.1	$ 103.4	$ 1,760.8
Revenue Excluding Transmission Costs ($ x 1000)	$ 132.9	$ 7,227.1	$ 4,622.2	$ 12,577.1	$ 6,966.8	$ 1,888.2	$ 75.7	$ 330.4	$ 2,005.9	$ 3,426.8	$ 1,425.5	$ 3,546.2	$ 44,224.9
Net Power Supply Expense ($ x 1000)	$ 24,895.5	$ 6,604.2	$ 10,606.0	$ (1,375.9)	$ 3,972.4	$ 13,865.1	$ 31,613.3	$ 26,688.6	$ 16,708.7	$ 13,100.9	$ 19,224.0	$ 15,013.1	$ 180,915.9

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
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1963

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	751,061.7	1,079,019.5	651,277.1	993,285.1	894,499.1	931,211.2	589,598.7	561,861.5	459,367.6	507,969.1	411,082.2	640,707.4	8,470,940.1
Bridger													
Energy (MWh)	470,742.4	423,492.2	470,097.5	381,313.7	344,352.5	374,272.6	470,376.8	470,444.5	453,087.4	470,741.4	455,557.1	470,742.4	5,255,220.4
Cost ($ x 1000)	$ 8,722.2	$ 7,849.2	$ 8,711.2	$ 7,068.3	$ 6,393.3	$ 6,982.2	$ 8,716.0	$ 8,717.1	$ 8,398.7	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 97,443.5
Boardman													
Energy (MWh)	30,108.7	24,074.8	31,774.9	2,987.7	-	28,040.9	36,724.7	36,742.7	34,898.7	37,473.9	36,225.3	37,429.1	336,481.4
Cost ($ x 1000)	$ 519.2	$ 424.4	$ 543.0	$ 51.3	$ -	$ 483.9	$ 613.6	$ 613.9	$ 584.7	$ 624.3	$ 603.6	$ 623.7	$ 5,685.5
Valmy													
Energy (MWh)	178,925.2	146,762.8	172,610.1	116,320.1	128,524.4	135,761.3	179,743.8	180,272.4	167,484.1	179,937.4	174,246.2	180,348.9	1,940,936.8
Cost ($ x 1000)	$ 4,560.7	$ 3,760.3	$ 4,409.9	$ 3,011.2	$ 3,315.4	$ 3,506.7	$ 4,580.3	$ 4,592.9	$ 4,278.2	$ 4,584.9	$ 4,439.7	$ 4,594.7	$ 49,634.8
Danskin													
Energy (MWh)	-	-	-	-	-	-	22,272.6	15,290.1	61.8	691.7	1,010.2	62.5	39,388.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 905.9	$ 637.5	$ 2.6	$ 31.1	$ 55.4	$ 4.1	$ 1,636.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 1,221.1	$ 952.7	$ 308.6	$ 346.4	$ 361.3	$ 319.4	$ 5,354.4
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	6,767.0	5,600.0	-	104.5	47.1	-	12,518.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 277.2	$ 234.8	$ -	$ 4.7	$ 2.6	$ -	$ 519.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 277.2	$ 234.8	$ -	$ 4.7	$ 2.6	$ -	$ 519.4
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	6,903.6	-	1,959.3	-	7,581.9	24,890.1	256,833.6	217,522.1	135,842.0	18,088.1	109,390.9	83,627.7	862,639.3
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	36,957.7	23,193.1	27,675.2	27,086.1	38,388.5	88,809.2	324,470.0	278,799.6	157,852.0	49,272.3	139,133.9	120,545.0	1,312,182.5
Market Cost ($ x 1000)	$ 271.2	$ -	$ 71.2	$ -	$ 235.5	$ 679.6	$ 11,645.0	$ 8,900.7	$ 5,174.0	$ 757.1	$ 5,279.4	$ 4,568.9	$ 37,582.6
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 1,820.1	$ 1,200.7	$ 1,053.1	$ 1,034.6	$ 1,410.6	$ 3,748.0	$ 15,231.8	$ 12,126.0	$ 6,323.7	$ 2,375.5	$ 7,132.8	$ 6,862.5	$ 60,319.4
Surplus Sales													
Energy (MWh)	91,643.6	541,280.9	223,363.1	471,262.5	191,067.4	205,515.6	5,327.7	13,182.2	66,852.8	132,475.1	56,807.0	48,543.1	2,047,321.1
Revenue Including Transmission Costs ($ x 1000)	$ 4,032.6	$ 15,580.9	$ 6,387.3	$ 11,584.9	$ 4,871.0	$ 5,615.7	$ 132.3	$ 339.6	$ 1,680.5	$ 3,798.9	$ 1,739.4	$ 1,739.2	$ 57,502.3
Transmission Costs ($ x 1000)	$ 91.6	$ 541.3	$ 223.4	$ 471.3	$ 191.1	$ 205.5	$ 5.3	$ 13.2	$ 66.9	$ 132.5	$ 56.8	$ 48.5	$ 2,047.3
Revenue Excluding Transmission Costs ($ x 1000)	$ 3,941.0	$ 15,039.6	$ 6,163.9	$ 11,113.7	$ 4,679.9	$ 5,410.2	$ 127.0	$ 326.4	$ 1,613.7	$ 3,666.4	$ 1,682.6	$ 1,690.7	$ 55,455.0
Net Power Supply Expense ($ x 1000)	$ 11,996.5	$ (1,517.6)	$ 8,868.6	$ 357.7	$ 6,754.6	$ 9,616.6	$ 30,513.0	$ 26,911.0	$ 18,280.2	$ 12,991.5	$ 19,298.2	$ 19,431.8	$ 163,502.0

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
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1964

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	744,308.7	888,938.9	660,377.1	1,194,980.1	801,703.1	1,255,222.1	608,485.3	593,140.2	625,763.6	531,566.5	501,744.4	1,019,950.1	9,426,180.0
Bridger													
Energy (MWh)	470,742.4	423,629.1	465,663.9	348,158.1	316,812.7	323,037.4	465,566.1	466,793.5	432,213.9	456,619.5	455,426.9	470,742.4	5,095,405.9
Cost ($ x 1000)	$ 8,722.2	$ 7,851.6	$ 8,635.6	$ 6,503.3	$ 5,923.9	$ 6,072.3	$ 8,634.0	$ 8,654.9	$ 8,043.0	$ 8,481.5	$ 8,438.6	$ 8,722.2	$ 94,683.1
Boardman													
Energy (MWh)	27,930.8	25,935.2	32,213.9	2,877.1	-	5,931.7	34,585.4	34,868.4	33,513.4	34,022.2	34,126.6	30,366.6	296,371.3
Cost ($ x 1000)	$ 488.1	$ 451.0	$ 549.2	$ 49.7	$ -	$ 108.5	$ 583.1	$ 587.1	$ 564.9	$ 575.0	$ 573.6	$ 522.9	$ 5,053.1
Valmy													
Energy (MWh)	177,938.1	149,473.8	131,134.6	3,358.4	45,745.9	10,774.7	139,642.5	141,297.8	109,863.2	138,984.4	166,484.7	177,814.0	1,392,512.1
Cost ($ x 1000)	$ 4,537.1	$ 3,824.9	$ 3,398.1	$ 87.6	$ 1,187.5	$ 284.6	$ 3,614.2	$ 3,648.9	$ 2,842.5	$ 3,596.2	$ 4,250.9	$ 4,534.1	$ 35,806.6
Danskin													
Energy (MWh)	-	-	-	-	-	-	10,836.5	9,205.3	0.1	-	309.1	-	20,351.0
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 371.8	$ 324.2	$ 0.0	$ -	$ 14.2	$ -	$ 710.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 687.0	$ 639.5	$ 305.9	$ 315.3	$ 320.2	$ 315.3	$ 4,428.1
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	1,059.4	6,409.2	-	-	-	-	7,468.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 36.6	$ 226.6	$ -	$ -	$ -	$ -	$ 263.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 36.6	$ 226.6	$ -	$ -	$ -	$ -	$ 263.2
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	13,702.6	-	2,522.1	-	92,706.1	6,683.3	297,039.9	230,371.0	62,559.6	15,143.4	64,566.8	108.3	785,403.2
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	43,756.7	23,193.1	28,238.0	27,086.1	123,512.7	70,602.5	364,676.2	291,648.4	84,569.6	46,327.7	94,309.8	37,025.6	1,234,946.4
Market Cost ($ x 1000)	$ 512.2	$ -	$ 68.8	$ -	$ 2,439.2	$ 123.8	$ 9,040.6	$ 7,545.9	$ 1,917.7	$ 469.3	$ 2,590.4	$ 4.5	$ 24,712.4
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 2,061.1	$ 1,200.7	$ 1,050.7	$ 1,034.6	$ 3,614.3	$ 3,192.2	$ 12,627.4	$ 10,771.2	$ 3,067.4	$ 2,087.8	$ 4,443.9	$ 2,298.1	$ 47,449.3
Surplus Sales													
Energy (MWh)	88,524.6	355,908.6	187,555.8	526,729.7	73,077.2	312,988.8	225.7	7,534.3	80,024.9	93,805.1	91,906.6	334,606.5	2,152,887.8
Revenue Including Transmission Costs ($ x 1000)	$ 3,299.2	$ 9,763.8	$ 4,887.8	$ 11,272.4	$ 1,462.7	$ 5,029.7	$ 4.8	$ 195.2	$ 1,942.5	$ 2,330.3	$ 2,474.9	$ 10,525.3	$ 53,188.5
Transmission Costs ($ x 1000)	$ 88.5	$ 355.9	$ 187.6	$ 526.7	$ 73.1	$ 313.0	$ 0.2	$ 7.5	$ 80.0	$ 93.8	$ 91.9	$ 334.6	$ 2,152.9
Revenue Excluding Transmission Costs ($ x 1000)	$ 3,210.7	$ 9,407.9	$ 4,700.2	$ 10,745.6	$ 1,389.7	$ 4,716.7	$ 4.6	$ 187.7	$ 1,862.5	$ 2,236.5	$ 2,383.0	$ 10,190.6	$ 51,035.6
Net Power Supply Expense ($ x 1000)	$ 12,913.1	$ 4,207.5	$ 9,248.7	$ (2,764.6)	$ 9,651.3	$ 5,246.9	$ 26,177.7	$ 24,340.5	$ 12,961.2	$ 12,819.3	$ 15,644.2	$ 6,201.9	$ 136,647.8

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
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1965

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,323,974.0	1,088,683.6	1,249,846.1	1,004,701.4	1,102,970.5	1,264,440.1	857,818.2	747,682.8	785,795.2	682,154.3	539,112.4	817,709.5	11,464,888.0
Bridger													
Energy (MWh)	462,136.7	371,671.8	386,919.8	277,230.1	258,842.0	303,541.2	425,173.5	403,348.6	368,149.6	413,689.4	452,032.3	470,742.4	4,593,477.3
Cost ($ x 1000)	$ 8,575.5	$ 6,954.8	$ 7,271.0	$ 5,243.0	$ 4,889.4	$ 5,733.5	$ 7,923.0	$ 7,522.8	$ 6,931.4	$ 7,749.8	$ 8,380.8	$ 8,722.2	$ 85,897.2
Boardman													
Energy (MWh)	21,399.5	14,925.7	24,924.1	1,292.1	-	15,819.7	33,629.4	33,029.8	32,517.7	33,228.3	33,451.2	35,498.9	279,716.4
Cost ($ x 1000)	$ 394.9	$ 284.5	$ 445.2	$ 23.4	$ -	$ 284.0	$ 569.4	$ 560.9	$ 550.7	$ 563.7	$ 564.0	$ 596.1	$ 4,836.8
Valmy													
Energy (MWh)	146,787.4	12,715.7	-	-	-	-	84,603.1	54,177.9	5,280.0	-	127,304.4	179,922.1	610,790.7
Cost ($ x 1000)	$ 3,783.9	$ 350.9	$ -	$ -	$ -	$ -	$ 2,218.3	$ 1,434.4	$ 144.8	$ -	$ 3,297.9	$ 4,584.5	$ 15,814.7
Danskin													
Energy (MWh)	-	-	-	-	0.2	-	9,096.7	5,991.0	1,185.1	0.9	329.4	-	16,603.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ 0.0	$ -	$ 259.4	$ 175.1	$ 35.4	$ 0.0	$ 12.5	$ -	$ 482.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 574.6	$ 490.3	$ 341.4	$ 315.3	$ 318.5	$ 315.3	$ 4,200.3
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	2,379.7	4,528.4	503.6	-	-	-	7,411.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 68.3	$ 133.0	$ 15.2	$ -	$ -	$ -	$ 216.5
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 68.3	$ 133.0	$ 15.2	$ -	$ -	$ -	$ 216.5
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	-	198.7	-	4,312.7	3,010.7	3,083.2	156,244.6	231,348.2	61,153.3	22,488.7	51,146.1	19,766.6	552,752.8
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	30,054.1	23,391.8	25,715.8	31,398.8	33,817.3	67,002.4	223,880.9	292,625.6	83,163.3	53,672.9	80,889.1	56,683.9	1,002,295.9
Market Cost ($ x 1000)	$ -	$ 3.9	$ -	$ 91.4	$ 65.8	$ 63.2	$ 4,199.8	$ 5,545.1	$ 1,572.9	$ 587.1	$ 1,656.0	$ 798.4	$ 14,583.5
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 1,548.9	$ 1,204.5	$ 981.9	$ 1,125.9	$ 1,240.9	$ 3,131.6	$ 7,786.6	$ 8,770.4	$ 2,722.5	$ 2,205.5	$ 3,509.5	$ 3,092.1	$ 37,320.4
Surplus Sales													
Energy (MWh)	608,199.6	356,127.2	557,334.3	264,892.2	180,932.9	298,223.8	11,955.8	5,555.5	70,695.7	69,030.5	72,623.7	159,264.6	2,654,835.8
Revenue Including Transmission Costs ($ x 1000)	$ 15,393.8	$ 7,173.7	$ 10,913.3	$ 4,760.5	$ 3,253.1	$ 4,864.5	$ 278.4	$ 157.6	$ 1,530.5	$ 1,536.7	$ 1,733.8	$ 4,548.8	$ 56,144.6
Transmission Costs ($ x 1000)	$ 608.2	$ 356.1	$ 557.3	$ 264.9	$ 180.9	$ 298.2	$ 12.0	$ 5.6	$ 70.7	$ 69.0	$ 72.6	$ 159.3	$ 2,654.8
Revenue Excluding Transmission Costs ($ x 1000)	$ 14,785.6	$ 6,817.5	$ 10,355.9	$ 4,495.6	$ 3,072.2	$ 4,566.3	$ 266.4	$ 152.0	$ 1,459.8	$ 1,467.7	$ 1,661.2	$ 4,389.5	$ 53,489.8
Net Power Supply Expense ($ x 1000)	$ (167.1)	$ 2,264.4	$ (1,342.5)	$ 2,202.6	$ 3,373.4	$ 4,888.7	$ 18,873.9	$ 18,759.9	$ 9,246.1	$ 9,366.7	$ 14,409.3	$ 12,920.6	$ 94,796.1

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
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1966

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	882,014.2	789,859.6	761,155.0	817,313.0	924,775.4	649,097.8	533,840.7	542,372.6	411,480.8	494,120.0	412,955.3	524,554.3	7,743,538.7
Bridger													
Energy (MWh)	470,742.4	425,186.7	470,405.7	377,667.1	347,707.7	379,481.5	470,742.4	470,742.4	455,557.1	470,742.4	455,557.1	470,742.4	5,265,274.8
Cost ($ x 1000)	$ 8,722.2	$ 7,878.1	$ 8,716.5	$ 7,006.2	$ 6,450.5	$ 7,071.0	$ 8,722.2	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 97,614.8
Boardman													
Energy (MWh)	31,063.4	31,347.7	33,860.3	3,035.0	-	27,992.0	37,734.6	37,099.2	35,878.4	37,921.7	36,809.1	36,489.3	349,230.7
Cost ($ x 1000)	$ 532.8	$ 528.2	$ 572.7	$ 52.0	$ -	$ 483.2	$ 628.0	$ 619.0	$ 598.6	$ 630.7	$ 611.9	$ 610.2	$ 5,867.4
Valmy													
Energy (MWh)	179,774.4	162,424.4	175,286.5	131,733.7	139,959.6	157,190.2	180,154.5	180,294.6	174,531.2	180,080.7	174,488.0	180,343.3	2,016,261.2
Cost ($ x 1000)	$ 4,581.0	$ 4,138.8	$ 4,473.9	$ 3,388.4	$ 3,592.8	$ 4,032.7	$ 4,590.1	$ 4,593.4	$ 4,446.5	$ 4,588.3	$ 4,445.5	$ 4,594.6	$ 51,465.9
Danskin													
Energy (MWh)	-	-	-	-	-	147.1	30,562.0	15,421.7	1,677.1	725.3	1,432.8	24.2	49,990.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 6.6	$ 1,375.2	$ 711.1	$ 79.2	$ 36.1	$ 87.0	$ 1.8	$ 2,297.0
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 312.5	$ 1,690.5	$ 1,026.3	$ 385.2	$ 351.4	$ 393.0	$ 317.0	$ 6,014.9
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	7,619.1	6,097.2	99.9	70.0	20.1	-	13,906.4
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 345.3	$ 282.9	$ 4.8	$ 3.5	$ 1.2	$ -	$ 637.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 345.3	$ 282.9	$ 4.8	$ 3.5	$ 1.2	$ -	$ 637.8
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	306.3	-	-	-	5,988.7	106,498.7	298,684.8	233,846.8	168,993.6	23,251.8	105,571.4	166,857.6	1,109,999.8
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	30,360.4	23,193.1	25,715.8	27,086.1	36,795.3	170,417.8	366,321.1	295,124.2	191,003.6	54,436.0	135,314.4	203,774.9	1,559,543.0
Market Cost ($ x 1000)	$ 9.5	$ -	$ -	$ -	$ 197.5	$ 3,512.0	$ 17,540.3	$ 10,449.6	$ 7,315.2	$ 1,090.4	$ 5,754.6	$ 9,609.4	$ 55,478.6
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 1,558.4	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,372.7	$ 6,580.4	$ 21,127.1	$ 13,674.9	$ 8,464.9	$ 2,708.9	$ 7,608.0	$ 11,903.0	$ 78,215.4
Surplus Sales													
Energy (MWh)	217,802.7	276,750.0	336,351.7	307,104.8	234,541.0	31,746.9	2,348.7	11,323.4	64,329.4	124,380.9	56,081.9	14,636.2	1,677,397.5
Revenue Including Transmission Costs ($ x 1000)	$ 10,854.3	$ 10,746.1	$ 10,922.2	$ 8,160.2	$ 6,122.6	$ 807.0	$ 63.6	$ 306.3	$ 1,716.6	$ 3,823.4	$ 1,936.3	$ 498.2	$ 55,956.7
Transmission Costs ($ x 1000)	$ 217.8	$ 276.8	$ 336.4	$ 307.1	$ 234.5	$ 31.7	$ 2.3	$ 11.3	$ 64.3	$ 124.4	$ 56.1	$ 14.6	$ 1,677.4
Revenue Excluding Transmission Costs ($ x 1000)	$ 10,636.5	$ 10,469.4	$ 10,585.9	$ 7,853.1	$ 5,888.0	$ 775.3	$ 61.2	$ 294.9	$ 1,652.2	$ 3,699.0	$ 1,880.2	$ 483.6	$ 54,279.3
Net Power Supply Expense ($ x 1000)	$ 5,073.1	$ 3,563.7	$ 4,474.4	$ 3,934.0	$ 5,843.1	$ 17,704.4	$ 37,042.0	$ 28,623.8	$ 20,688.6	$ 13,306.0	$ 19,620.3	$ 25,663.4	$ 185,536.9

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
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1967

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	577,583.9	934,760.3	570,779.4	793,639.1	796,352.3	1,239,817.8	624,187.0	545,740.2	544,465.0	576,998.4	529,580.5	739,517.4	8,473,421.3
Bridger													
Energy (MWh)	470,742.4	421,721.4	470,628.0	382,017.3	335,981.8	345,451.8	463,096.0	469,793.8	450,509.9	470,327.9	455,557.1	470,742.4	5,206,569.9
Cost ($ x 1000)	$ 8,722.2	$ 7,819.1	$ 8,720.2	$ 7,080.3	$ 6,250.6	$ 6,450.6	$ 8,591.9	$ 8,706.0	$ 8,354.8	$ 8,715.1	$ 8,440.8	$ 8,722.2	$ 96,573.9
Boardman													
Energy (MWh)	26,598.1	23,424.4	30,742.1	3,071.5	-	7,782.6	34,447.9	36,052.3	35,004.4	36,567.2	35,027.7	36,635.5	305,353.8
Cost ($ x 1000)	$ 469.1	$ 415.1	$ 528.2	$ 52.5	$ -	$ 147.3	$ 580.5	$ 604.0	$ 586.2	$ 611.4	$ 586.5	$ 612.3	$ 5,193.1
Valmy													
Energy (MWh)	174,270.1	144,816.5	173,199.1	122,893.3	118,236.1	70,056.7	172,234.5	179,661.4	156,386.2	172,520.5	174,445.6	180,135.9	1,838,855.8
Cost ($ x 1000)	$ 4,449.6	$ 3,713.9	$ 4,423.9	$ 3,175.3	$ 3,059.2	$ 1,839.2	$ 4,401.1	$ 4,578.3	$ 4,013.5	$ 4,407.8	$ 4,444.5	$ 4,589.6	$ 47,095.8
Danskin													
Energy (MWh)	-	-	-	-	-	-	9,253.4	13,736.9	18.3	-	58.9	-	23,067.5
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 361.2	$ 549.8	$ 0.8	$ -	$ 3.1	$ -	$ 914.9
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 676.5	$ 865.0	$ 306.7	$ 315.3	$ 309.0	$ 315.3	$ 4,632.7
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	1,046.2	7,763.6	-	-	-	-	8,809.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 41.1	$ 312.5	$ -	$ -	$ -	$ -	$ 353.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 41.1	$ 312.5	$ -	$ -	$ -	$ -	$ 353.6
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	107,676.2	-	7,331.1	-	45,537.7	3,720.2	257,370.4	234,088.2	85,697.1	6,534.3	45,309.8	36,823.9	830,089.0
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	137,730.3	23,193.1	33,047.0	27,086.1	76,344.3	67,639.4	325,006.7	295,365.6	107,707.1	37,718.5	75,052.8	73,741.2	1,279,632.2
Market Cost ($ x 1000)	$ 4,238.9	$ -	$ 252.7	$ -	$ 1,366.9	$ 75.3	$ 8,962.8	$ 8,929.6	$ 3,156.4	$ 254.8	$ 2,085.2	$ 1,892.3	$ 31,215.1
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 5,787.8	$ 1,200.7	$ 1,234.6	$ 1,034.6	$ 2,542.0	$ 3,143.7	$ 12,549.6	$ 12,155.0	$ 4,306.1	$ 1,873.2	$ 3,938.7	$ 4,185.9	$ 53,951.9
Surplus Sales													
Energy (MWh)	10,772.7	392,654.3	148,324.0	278,977.2	112,217.4	378,168.7	4,646.1	12,285.3	88,192.1	180,417.4	109,227.5	99,480.2	1,815,362.8
Revenue Including Transmission Costs ($ x 1000)	$ 412.4	$ 11,010.0	$ 4,127.4	$ 7,301.3	$ 2,370.8	$ 6,746.7	$ 111.9	$ 316.6	$ 2,252.5	$ 5,100.8	$ 3,222.8	$ 3,514.7	$ 46,487.8
Transmission Costs ($ x 1000)	$ 10.8	$ 392.7	$ 148.3	$ 279.0	$ 112.2	$ 378.2	$ 4.6	$ 12.3	$ 88.2	$ 180.4	$ 109.2	$ 99.5	$ 1,815.4
Revenue Excluding Transmission Costs ($ x 1000)	$ 401.6	$ 10,617.4	$ 3,979.1	$ 7,022.3	$ 2,258.5	$ 6,368.6	$ 107.3	$ 304.3	$ 2,164.3	$ 4,920.4	$ 3,113.5	$ 3,415.2	$ 44,672.4
Net Power Supply Expense ($ x 1000)	$ 19,342.3	$ 2,818.7	$ 11,243.2	$ 4,626.3	$ 9,908.6	$ 5,518.1	$ 26,733.4	$ 26,916.5	$ 15,403.0	$ 11,002.4	$ 14,606.0	$ 15,010.1	$ 163,128.7

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
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1968

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	831,979.3	908,321.8	897,893.4	752,417.3	732,429.2	918,490.7	527,257.5	594,488.2	571,672.3	526,958.4	525,515.6	695,424.0	8,482,847.7
Bridger													
Energy (MWh)	470,742.4	424,768.0	467,319.9	382,059.5	338,776.4	369,864.4	470,426.2	469,677.3	440,399.1	467,321.9	455,526.9	470,742.4	5,227,624.4
Cost ($ x 1000)	$ 8,722.2	$ 7,871.0	$ 8,663.9	$ 7,081.1	$ 6,298.3	$ 6,907.1	$ 8,716.8	$ 8,704.0	$ 8,182.5	$ 8,663.9	$ 8,440.3	$ 8,722.2	$ 96,973.2
Boardman													
Energy (MWh)	28,575.9	24,792.3	28,243.1	2,959.6	-	24,107.4	36,262.6	35,888.5	33,557.4	34,430.4	31,675.2	35,214.8	315,707.2
Cost ($ x 1000)	$ 497.3	$ 434.7	$ 492.6	$ 50.9	$ -	$ 421.4	$ 607.0	$ 601.7	$ 565.5	$ 580.9	$ 538.7	$ 592.1	$ 5,382.6
Valmy													
Energy (MWh)	178,124.8	147,622.7	160,635.7	121,861.4	121,338.9	116,762.2	176,650.4	179,531.2	152,248.1	171,762.4	173,382.7	180,256.4	1,880,177.0
Cost ($ x 1000)	$ 4,541.6	$ 3,780.9	$ 4,124.3	$ 3,150.6	$ 3,138.6	$ 3,025.2	$ 4,506.4	$ 4,575.2	$ 3,914.9	$ 4,389.4	$ 4,419.1	$ 4,592.5	$ 48,158.6
Danskin													
Energy (MWh)	-	-	-	-	-	-	20,630.1	11,274.2	-	-	-	-	31,904.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 808.7	$ 453.3	$ -	$ -	$ -	$ -	$ 1,262.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 1,124.0	$ 768.6	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 4,979.9
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	3,446.2	6,972.9	-	-	-	-	10,419.2
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 136.1	$ 281.8	$ -	$ -	$ -	$ -	$ 417.9
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 136.1	$ 281.8	$ -	$ -	$ -	$ -	$ 417.9
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	381.5	-	-	-	75,037.8	29,788.9	324,564.9	197,238.3	72,868.6	15,192.2	48,838.0	53,445.4	817,355.5
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	30,435.6	23,193.1	25,715.8	27,086.1	105,844.4	93,708.1	392,201.2	258,515.7	94,878.6	46,376.4	78,581.0	90,362.7	1,266,898.6
Market Cost ($ x 1000)	$ 8.8	$ -	$ -	$ -	$ 2,256.2	$ 822.1	$ 14,729.3	$ 7,544.4	$ 2,614.9	$ 562.5	$ 2,108.4	$ 2,695.5	$ 33,342.0
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 1,557.7	$ 1,200.7	$ 981.9	$ 1,034.6	$ 3,431.3	$ 3,890.5	$ 18,316.1	$ 10,769.7	$ 3,764.5	$ 2,180.9	$ 3,961.8	$ 4,989.1	$ 56,078.9
Surplus Sales													
Energy (MWh)	163,705.8	373,436.4	449,736.3	236,653.9	83,691.7	170,353.2	2,248.3	20,519.4	86,856.7	133,134.3	104,186.4	70,708.1	1,895,230.8
Revenue Including Transmission Costs ($ x 1000)	$ 6,870.6	$ 10,989.8	$ 11,878.6	$ 6,147.3	$ 1,758.7	$ 4,236.4	$ 54.4	$ 524.7	$ 2,207.3	$ 3,540.1	$ 2,825.5	$ 2,248.4	$ 53,281.9
Transmission Costs ($ x 1000)	$ 163.7	$ 373.4	$ 449.7	$ 236.7	$ 83.7	$ 170.4	$ 2.2	$ 20.5	$ 86.9	$ 133.1	$ 104.2	$ 70.7	$ 1,895.2
Revenue Excluding Transmission Costs ($ x 1000)	$ 6,706.9	$ 10,616.4	$ 11,428.9	$ 5,910.6	$ 1,675.0	$ 4,066.1	$ 52.1	$ 504.2	$ 2,120.5	$ 3,407.0	$ 2,721.3	$ 2,177.7	$ 51,386.7
Net Power Supply Expense ($ x 1000)	$ 8,927.1	$ 2,958.1	$ 3,149.0	$ 5,712.4	$ 11,508.4	$ 10,483.9	$ 33,354.3	$ 25,196.8	$ 14,612.9	$ 12,723.4	$ 14,944.5	$ 17,033.4	$ 160,604.3

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
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1969

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,115,826.3	1,110,067.6	1,196,755.0	1,087,883.7	1,106,782.3	814,444.7	593,103.9	575,586.3	458,761.7	519,653.8	414,703.2	604,860.0	9,598,428.5
Bridger													
Energy (MWh)	469,899.0	412,889.3	462,643.7	325,599.1	310,403.9	347,030.6	467,093.4	467,838.6	435,715.1	460,836.7	455,557.1	470,742.4	5,086,248.7
Cost ($ x 1000)	$ 8,707.8	$ 7,657.2	$ 8,584.2	$ 6,118.8	$ 5,814.7	$ 6,509.4	$ 8,660.0	$ 8,672.7	$ 8,102.7	$ 8,553.4	$ 8,440.8	$ 8,722.2	$ 94,543.9
Boardman													
Energy (MWh)	24,115.1	22,798.1	28,885.5	1,393.5	-	25,028.9	35,162.9	36,444.9	34,079.3	36,333.8	35,237.9	36,023.0	315,502.8
Cost ($ x 1000)	$ 430.8	$ 406.2	$ 501.7	$ 25.1	$ -	$ 440.9	$ 591.3	$ 609.6	$ 573.0	$ 608.0	$ 589.5	$ 603.6	$ 5,379.7
Valmy													
Energy (MWh)	167,630.1	136,543.5	88,763.9	-	-	7,959.3	139,117.0	143,230.2	115,135.1	139,391.9	171,400.1	180,001.7	1,289,172.9
Cost ($ x 1000)	$ 4,291.1	$ 3,511.9	$ 2,316.6	$ -	$ -	$ 208.7	$ 3,600.1	$ 3,695.0	$ 2,980.1	$ 3,605.9	$ 4,371.7	$ 4,586.4	$ 33,167.6
Danskin													
Energy (MWh)	-	-	-	-	-	-	13,524.2	16,889.0	560.4	2.1	2,001.8	178.6	33,156.0
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 460.6	$ 590.6	$ 20.0	$ 0.1	$ 91.5	$ 9.8	$ 1,172.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 775.9	$ 905.9	$ 326.0	$ 315.3	$ 397.5	$ 325.0	$ 4,890.5
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	1,669.9	12,200.8	-	-	320.6	-	14,191.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 57.3	$ 428.3	$ -	$ -	$ 14.8	$ -	$ 500.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 57.3	$ 428.3	$ -	$ -	$ 14.8	$ -	$ 500.3
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	-	1.0	-	-	3,810.2	118,759.5	307,345.2	226,999.7	159,724.0	16,665.5	105,232.7	111,501.9	1,050,039.6
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	30,054.1	23,194.1	25,715.8	27,086.1	34,616.8	182,678.6	374,981.5	288,277.1	181,734.0	47,849.7	134,975.7	148,419.2	1,499,582.8
Market Cost ($ x 1000)	$ -	$ 0.0	$ -	$ -	$ 94.6	$ 2,595.4	$ 10,039.3	$ 8,153.6	$ 4,859.9	$ 545.7	$ 4,266.7	$ 5,181.0	$ 35,736.1
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,269.7	$ 5,663.7	$ 13,626.1	$ 11,378.9	$ 6,009.6	$ 2,164.1	$ 6,120.1	$ 7,474.6	$ 58,473.0
Surplus Sales													
Energy (MWh)	431,372.5	550,231.1	672,692.3	392,232.3	237,105.8	24,562.5	27.1	4,638.3	20,086.7	90,352.9	53,701.4	38,932.6	2,515,935.5
Revenue Including Transmission Costs ($ x 1000)	$ 13,977.6	$ 13,568.5	$ 15,462.6	$ 7,186.2	$ 4,496.6	$ 544.7	$ 0.6	$ 119.3	$ 468.8	$ 2,325.6	$ 1,440.6	$ 1,099.9	$ 60,690.9
Transmission Costs ($ x 1000)	$ 431.4	$ 550.2	$ 672.7	$ 392.2	$ 237.1	$ 24.6	$ 0.0	$ 4.6	$ 20.1	$ 90.4	$ 53.7	$ 38.9	$ 2,515.9
Revenue Excluding Transmission Costs ($ x 1000)	$ 13,546.3	$ 13,018.2	$ 14,789.9	$ 6,793.9	$ 4,259.5	$ 520.1	$ 0.5	$ 114.6	$ 448.7	$ 2,235.3	$ 1,386.9	$ 1,061.0	$ 58,175.0
Net Power Supply Expense ($ x 1000)	$ 1,747.6	$ 45.1	$ (2,090.2)	$ 690.4	$ 3,140.2	$ 12,608.7	$ 27,310.2	$ 25,575.6	$ 17,542.6	$ 13,011.5	$ 18,547.5	$ 20,650.8	$ 138,780.0

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
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1970

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,042,890.7	1,108,014.3	825,019.6	1,019,594.0	1,084,516.2	1,271,382.9	740,319.6	648,707.1	633,363.3	557,165.9	521,352.9	821,595.5	10,273,921.9
Bridger													
Energy (MWh)	470,741.1	424,584.3	469,819.1	371,193.3	322,574.1	356,812.8	466,708.1	467,913.5	447,865.5	467,891.6	455,557.1	470,742.4	5,192,402.8
Cost ($ x 1000)	$ 8,722.2	$ 7,867.8	$ 8,706.5	$ 6,895.9	$ 6,022.1	$ 6,684.6	$ 8,653.4	$ 8,674.0	$ 8,309.7	$ 8,673.6	$ 8,440.8	$ 8,722.2	$ 96,372.9
Boardman													
Energy (MWh)	28,228.6	26,494.8	33,661.4	3,300.4	-	20,994.2	36,743.4	36,309.6	34,792.7	37,433.7	35,349.6	36,119.1	329,427.5
Cost ($ x 1000)	$ 492.4	$ 459.0	$ 569.9	$ 55.8	$ -	$ 372.8	$ 613.9	$ 607.7	$ 583.1	$ 623.7	$ 591.1	$ 605.0	$ 5,574.2
Valmy													
Energy (MWh)	175,994.3	150,062.6	141,418.4	60,451.2	69,949.1	35,847.7	151,184.7	156,357.6	131,426.5	154,638.2	174,255.3	180,255.0	1,581,840.7
Cost ($ x 1000)	$ 4,490.7	$ 3,839.1	$ 3,658.6	$ 1,576.8	$ 1,820.8	$ 941.5	$ 3,892.4	$ 4,017.6	$ 3,396.4	$ 3,981.3	$ 4,439.9	$ 4,592.5	$ 40,647.6
Danskin													
Energy (MWh)	-	-	-	-	-	-	16,321.0	14,104.7	264.5	178.2	246.8	-	31,115.2
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 583.9	$ 518.6	$ 9.9	$ 7.0	$ 11.9	$ -	$ 1,131.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 899.1	$ 833.8	$ 315.9	$ 322.3	$ 317.8	$ 315.3	$ 4,849.2
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	4,329.5	9,826.6	114.6	164.2	-	-	14,434.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 156.0	$ 362.3	$ 4.3	$ 6.5	$ -	$ -	$ 529.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 156.0	$ 362.3	$ 4.3	$ 6.5	$ -	$ -	$ 529.2
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	-	-	-	-	2,980.3	509.4	156,012.9	160,879.5	49,941.4	8,652.8	52,640.6	10,408.4	442,025.3
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	33,786.9	64,428.5	223,649.2	222,157.0	71,951.4	39,837.0	82,383.6	47,325.7	891,568.5
Market Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ 81.1	$ 15.0	$ 6,640.3	$ 6,057.1	$ 1,681.9	$ 322.9	$ 2,240.0	$ 521.4	$ 17,559.8
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,256.3	$ 3,083.4	$ 10,227.2	$ 9,282.4	$ 2,831.5	$ 1,941.4	$ 4,093.5	$ 2,815.0	$ 40,296.6
Surplus Sales													
Energy (MWh)	371,756.8	577,087.6	365,562.7	431,895.0	296,129.2	396,886.6	14,629.8	19,547.4	113,879.9	143,593.6	108,650.3	154,745.4	2,994,364.2
Revenue Including Transmission Costs ($ x 1000)	$ 13,874.0	$ 15,797.2	$ 9,776.4	$ 9,976.7	$ 6,730.8	$ 7,346.8	$ 370.6	$ 518.6	$ 2,882.0	$ 3,877.0	$ 3,061.5	$ 5,322.0	$ 79,533.6
Transmission Costs ($ x 1000)	$ 371.8	$ 577.1	$ 365.6	$ 431.9	$ 296.1	$ 396.9	$ 14.6	$ 19.5	$ 113.9	$ 143.6	$ 108.7	$ 154.7	$ 2,994.4
Revenue Excluding Transmission Costs ($ x 1000)	$ 13,502.3	$ 15,220.1	$ 9,410.8	$ 9,544.8	$ 6,434.7	$ 6,950.0	$ 355.9	$ 499.1	$ 2,768.1	$ 3,733.4	$ 2,952.9	$ 5,167.2	$ 76,539.2
Net Power Supply Expense ($ x 1000)	$ 2,067.2	$ (1,566.3)	$ 4,821.3	$ 324.1	$ 2,979.8	$ 4,438.2	$ 24,086.1	$ 23,278.7	$ 12,673.0	$ 11,815.5	$ 14,930.2	$ 11,882.7	$ 111,730.5

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1971

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,331,292.2	1,098,812.7	1,164,052.7	954,863.0	1,187,807.4	1,261,722.2	1,164,040.9	711,138.3	923,402.3	772,098.7	659,775.9	954,983.9	12,183,990.2
Bridger													
Energy (MWh)	457,012.9	320,282.6	352,483.5	262,787.9	225,749.8	206,118.5	378,216.0	387,688.7	346,865.8	382,880.3	441,665.5	470,631.6	4,232,383.0
Cost ($ x 1000)	$ 8,488.2	$ 6,007.5	$ 6,676.6	$ 4,974.5	$ 4,275.4	$ 3,917.5	$ 7,103.9	$ 7,277.6	$ 6,538.6	$ 7,213.5	$ 8,204.1	$ 8,720.3	$ 79,397.6
Boardman													
Energy (MWh)	21,828.1	12,110.6	21,168.9	1,617.4	-	5,370.9	30,561.1	32,100.3	33,222.1	36,454.3	32,743.5	35,021.5	262,198.9
Cost ($ x 1000)	$ 401.0	$ 233.3	$ 382.9	$ 29.2	$ -	$ 98.5	$ 522.3	$ 547.6	$ 560.7	$ 609.7	$ 553.9	$ 589.3	$ 4,528.7
Valmy													
Energy (MWh)	153,515.3	-	-	-	-	-	47,050.1	40,157.1	-	-	67,604.0	151,578.1	459,904.6
Cost ($ x 1000)	$ 3,953.3	$ -	$ -	$ -	$ -	$ -	$ 1,267.2	$ 1,093.5	$ -	$ -	$ 1,773.4	$ 3,908.3	$ 11,995.7
Danskin													
Energy (MWh)	-	-	-	0.3	-	74.8	7,014.3	8,269.9	2,176.0	491.2	65.9	-	18,092.6
Cost ($ x 1000)	$ -	$ -	$ -	$ 0.0	$ -	$ 2.0	$ 187.4	$ 226.3	$ 60.9	$ 14.5	$ 2.3	$ -	$ 493.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 307.9	$ 502.7	$ 541.5	$ 366.9	$ 329.7	$ 308.3	$ 315.3	$ 4,211.3
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	1,423.8	7,153.5	942.6	142.2	-	-	9,662.1
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 38.3	$ 196.8	$ 26.6	$ 4.2	$ -	$ -	$ 265.9
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 38.3	$ 196.8	$ 26.6	$ 4.2	$ -	$ -	$ 265.9
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	-	4,186.7	83.3	9,323.2	2,900.3	25,003.2	32,980.1	296,800.4	35,119.9	10,871.9	15,737.1	416.6	433,422.7
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	30,054.1	27,379.8	25,799.1	36,409.3	33,706.9	88,922.3	100,616.4	358,077.9	57,129.8	42,056.1	45,480.2	37,333.9	882,965.9
Market Cost ($ x 1000)	$ -	$ 85.5	$ 1.7	$ 206.9	$ 52.3	$ 504.3	$ 752.8	$ 6,966.2	$ 881.0	$ 257.2	$ 453.5	$ 16.0	$ 10,177.5
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 1,548.9	$ 1,286.1	$ 983.6	$ 1,241.5	$ 1,227.4	$ 3,572.7	$ 4,339.6	$ 10,191.5	$ 2,030.7	$ 1,875.7	$ 2,307.0	$ 2,309.6	$ 32,914.4
Surplus Sales													
Energy (MWh)	617,550.5	303,324.3	433,432.7	205,947.7	232,567.0	209,629.2	104,296.9	8,757.1	157,840.0	120,407.6	86,840.0	248,256.8	2,728,849.9
Revenue Including Transmission Costs ($ x 1000)	$ 15,396.0	$ 5,728.1	$ 8,336.9	$ 3,787.6	$ 3,641.2	$ 3,092.5	$ 2,227.3	$ 203.2	$ 3,161.3	$ 2,762.2	$ 2,104.2	$ 6,988.6	$ 57,429.0
Transmission Costs ($ x 1000)	$ 617.6	$ 303.3	$ 433.4	$ 205.9	$ 232.6	$ 209.6	$ 104.3	$ 8.8	$ 157.8	$ 120.4	$ 86.8	$ 248.3	$ 2,728.8
Revenue Excluding Transmission Costs ($ x 1000)	$ 14,778.5	$ 5,424.7	$ 7,903.5	$ 3,581.7	$ 3,408.6	$ 2,882.8	$ 2,123.0	$ 194.4	$ 3,003.5	$ 2,641.8	$ 2,017.3	$ 6,740.3	$ 54,700.1
Net Power Supply Expense ($ x 1000)	$ (71.8)	$ 2,389.6	$ 454.9	$ 2,969.5	$ 2,409.5	$ 5,013.8	$ 11,650.9	$ 19,654.1	$ 6,520.0	$ 7,391.1	$ 11,129.3	$ 9,102.4	$ 78,613.4

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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,145,337.0	1,107,294.3	1,137,510.7	975,701.4	1,024,150.4	1,270,427.6	742,959.6	675,393.3	644,099.4	655,854.6	581,649.0	854,416.9	10,814,794.0
Bridger													
Energy (MWh)	459,410.9	325,268.2	236,795.6	233,348.7	181,418.2	217,952.5	361,109.3	356,259.2	319,415.8	371,117.2	423,863.7	470,320.4	3,956,279.6
Cost ($ x 1000)	$ 8,529.1	$ 6,117.9	$ 4,520.7	$ 4,426.0	$ 3,445.1	$ 4,154.2	$ 6,808.6	$ 6,715.6	$ 6,032.2	$ 7,013.0	$ 7,900.7	$ 8,715.0	$ 74,378.0
Boardman													
Energy (MWh)	21,085.9	13,877.7	4,054.4	162.2	-	-	25,308.0	29,219.8	32,390.3	35,977.8	33,806.1	33,791.7	229,673.8
Cost ($ x 1000)	$ 390.4	$ 265.9	$ 78.9	$ 3.4	$ -	$ -	$ 435.5	$ 500.7	$ 548.9	$ 602.9	$ 569.1	$ 571.8	$ 3,967.5
Valmy													
Energy (MWh)	146,997.1	90.2	-	-	-	-	14,240.9	18,907.4	-	-	30,209.0	143,462.7	353,907.3
Cost ($ x 1000)	$ 3,789.6	$ 2.5	$ -	$ -	$ -	$ -	$ 396.3	$ 520.2	$ -	$ -	$ 806.8	$ 3,702.8	$ 9,218.3
Danskin													
Energy (MWh)	-	-	-	2.8	1.7	407.7	7,411.6	7,662.0	3,577.9	1,321.5	649.8	-	21,035.0
Cost ($ x 1000)	$ -	$ -	$ -	$ 0.1	$ 0.0	$ 10.1	$ 185.9	$ 196.8	$ 94.0	$ 36.5	$ 21.7	$ -	$ 545.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 306.0	$ 315.3	$ 316.1	$ 501.2	$ 512.0	$ 400.0	$ 351.8	$ 327.6	$ 315.3	$ 4,263.0
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	3.2	1,295.3	6,349.6	2,154.1	212.0	68.4	-	10,082.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 0.1	$ 32.7	$ 164.0	$ 57.0	$ 5.9	$ 2.3	$ -	$ 262.0
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ 0.1	$ 32.7	$ 164.0	$ 57.0	$ 5.9	$ 2.3	$ -	$ 262.0
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	-	1,919.6	4,737.7	9,257.4	59,806.8	14,561.9	404,664.7	381,205.3	189,317.6	48,735.9	95,045.1	9,279.0	1,218,531.0
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	30,054.1	25,112.7	30,453.5	36,343.5	90,613.4	78,481.0	472,301.1	442,482.7	211,327.6	79,920.1	124,788.1	46,196.3	1,668,074.2
Market Cost ($ x 1000)	$ -	$ 39.0	$ 93.3	$ 169.8	$ 1,090.7	$ 249.1	$ 8,505.7	$ 8,207.3	$ 4,265.4	$ 1,145.2	$ 2,688.0	$ 318.7	$ 26,772.1
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 1,548.9	$ 1,239.7	$ 1,075.2	$ 1,204.4	$ 2,265.8	$ 3,317.5	$ 12,092.5	$ 11,432.6	$ 5,415.1	$ 2,763.6	$ 4,541.4	$ 2,612.3	$ 49,509.0
Surplus Sales													
Energy (MWh)	426,732.9	316,381.6	278,742.6	195,828.5	81,486.6	214,692.4	-	445.4	7,066.3	30,687.9	34,539.1	146,895.7	1,733,499.1
Revenue Including Transmission Costs ($ x 1000)	$ 10,622.7	$ 6,072.3	$ 4,687.0	$ 3,194.9	$ 1,138.9	$ 2,871.4	$ -	$ 13.2	$ 159.1	$ 674.6	$ 763.4	$ 3,870.9	$ 34,068.3
Transmission Costs ($ x 1000)	$ 426.7	$ 316.4	$ 278.7	$ 195.8	$ 81.5	$ 214.7	$ -	$ 0.4	$ 7.1	$ 30.7	$ 34.5	$ 146.9	$ 1,733.5
Revenue Excluding Transmission Costs ($ x 1000)	$ 10,195.9	$ 5,755.9	$ 4,408.3	$ 2,999.0	$ 1,057.4	$ 2,656.7	$ -	$ 12.8	$ 152.0	$ 643.9	$ 728.8	$ 3,724.0	$ 32,334.8
Net Power Supply Expense ($ x 1000)	$ 4,377.3	$ 2,157.4	$ 1,581.8	$ 2,940.8	$ 4,968.8	$ 5,131.1	$ 20,266.8	$ 19,832.4	$ 12,301.1	$ 10,093.3	$ 13,419.1	$ 12,193.2	$ 109,263.1

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1973

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	952,408.7	869,653.3	749,954.0	736,624.0	1,209,048.8	712,455.7	553,135.2	559,112.2	619,764.9	492,952.0	460,839.0	775,549.1	8,691,496.9
Bridger													
Energy (MWh)	470,742.4	425,186.7	470,667.1	383,033.0	345,992.5	380,766.4	470,631.7	470,742.4	454,898.0	470,716.9	455,557.1	470,742.4	5,269,676.5
Cost ($ x 1000)	$ 8,722.2	$ 7,878.1	$ 8,720.9	$ 7,097.6	$ 6,421.2	$ 7,092.9	$ 8,720.3	$ 8,722.2	$ 8,429.6	$ 8,721.8	$ 8,440.8	$ 8,722.2	$ 97,689.9
Boardman													
Energy (MWh)	32,541.8	33,173.8	36,932.9	3,535.5	-	28,300.1	38,328.1	37,561.7	35,681.0	37,199.3	33,798.6	32,219.9	349,272.5
Cost ($ x 1000)	$ 553.9	$ 554.3	$ 616.6	$ 59.1	$ -	$ 487.6	$ 636.5	$ 625.6	$ 595.8	$ 620.4	$ 569.0	$ 549.3	$ 5,868.0
Valmy													
Energy (MWh)	180,025.4	162,422.8	178,045.0	135,298.5	125,515.0	138,696.7	177,392.7	180,348.9	174,271.4	180,347.7	174,319.2	179,528.7	1,986,211.8
Cost ($ x 1000)	$ 4,587.0	$ 4,138.8	$ 4,539.7	$ 3,473.5	$ 3,243.6	$ 3,577.5	$ 4,519.5	$ 4,594.7	$ 4,440.3	$ 4,594.7	$ 4,441.4	$ 4,575.1	$ 50,725.7
Danskin													
Energy (MWh)	-	-	-	-	-	-	35,964.3	22,065.4	824.0	830.0	1.4	-	59,685.0
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,509.8	$ 950.0	$ 36.3	$ 38.6	$ 0.1	$ -	$ 2,534.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 1,825.1	$ 1,265.3	$ 342.3	$ 353.8	$ 306.0	$ 315.3	$ 6,252.6
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	11,912.7	11,347.1	27.0	77.5	-	-	23,364.4
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 503.7	$ 491.1	$ 1.2	$ 3.6	$ -	$ -	$ 999.7
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 503.7	$ 491.1	$ 1.2	$ 3.6	$ -	$ -	$ 999.7
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	-	-	-	-	-	82,112.5	273,026.5	211,103.4	52,670.1	23,168.4	83,246.3	24,325.6	749,652.8
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	146,031.7	340,662.8	272,380.8	74,680.1	54,352.6	112,989.3	61,242.9	1,199,196.0
Market Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 2,518.1	$ 18,539.3	$ 9,808.7	$ 2,180.8	$ 1,011.8	$ 3,902.7	$ 1,259.0	$ 39,220.3
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 5,586.5	$ 22,126.1	$ 13,034.0	$ 3,330.5	$ 2,630.2	$ 5,756.1	$ 3,552.6	$ 61,957.2
Surplus Sales													
Energy (MWh)	289,620.3	358,368.2	331,243.1	235,847.0	496,665.8	53,671.0	3,401.8	17,730.0	154,247.5	122,760.7	77,009.6	117,990.8	2,258,555.7
Revenue Including Transmission Costs ($ x 1000)	$ 13,925.3	$ 13,374.6	$ 10,713.8	$ 6,715.1	$ 12,393.4	$ 1,427.4	$ 91.1	$ 493.7	$ 4,295.9	$ 3,508.4	$ 2,235.3	$ 4,051.5	$ 73,225.5
Transmission Costs ($ x 1000)	$ 289.6	$ 358.4	$ 331.2	$ 235.8	$ 496.7	$ 53.7	$ 3.4	$ 17.7	$ 154.2	$ 122.8	$ 77.0	$ 118.0	$ 2,258.6
Revenue Excluding Transmission Costs ($ x 1000)	$ 13,635.7	$ 13,016.2	$ 10,382.5	$ 6,479.3	$ 11,896.7	$ 1,373.8	$ 87.7	$ 476.0	$ 4,141.7	$ 3,385.6	$ 2,158.3	$ 3,933.5	$ 70,966.9
Net Power Supply Expense ($ x 1000)	$ 2,091.6	$ 1,042.9	$ 4,791.9	$ 5,491.5	$ (741.5)	$ 15,676.6	$ 38,243.4	$ 28,256.9	$ 12,997.9	$ 13,538.9	$ 17,355.1	$ 13,781.0	$ 152,526.1

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1974

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,243,885.1	1,089,114.8	1,140,918.1	958,951.0	1,020,682.8	1,237,857.9	924,670.0	710,095.0	611,897.8	728,628.8	586,560.1	827,220.9	11,080,482.3
Bridger													
Energy (MWh)	439,383.0	319,095.8	188,295.0	190,319.1	196,266.1	205,600.0	345,171.0	343,776.1	293,804.6	355,576.4	405,633.3	468,042.3	3,750,962.7
Cost ($ x 1000)	$ 8,187.7	$ 6,020.2	$ 3,587.9	$ 3,631.6	$ 3,733.4	$ 3,930.3	$ 6,514.4	$ 6,487.8	$ 5,567.5	$ 6,710.5	$ 7,590.0	$ 8,676.2	$ 70,637.5
Boardman													
Energy (MWh)	15,682.2	11,190.0	15,944.7	394.6	-	-	19,612.5	29,160.9	30,358.5	37,590.9	35,742.7	35,182.5	230,859.6
Cost ($ x 1000)	$ 299.6	$ 220.7	$ 296.6	$ 7.9	$ -	$ -	$ 340.3	$ 499.6	$ 516.4	$ 626.0	$ 596.7	$ 591.6	$ 3,995.4
Valmy													
Energy (MWh)	102,947.3	-	-	-	-	-	14,213.9	20,773.0	-	-	20,665.9	116,755.2	275,355.3
Cost ($ x 1000)	$ 2,684.3	$ -	$ -	$ -	$ -	$ -	$ 398.3	$ 573.4	$ -	$ -	$ 559.7	$ 3,030.8	$ 7,246.5
Danskin													
Energy (MWh)	-	-	-	12.3	18.5	868.6	7,319.4	8,567.1	3,523.7	2,864.8	1,696.3	-	24,870.7
Cost ($ x 1000)	$ -	$ -	$ -	$ 0.3	$ 0.4	$ 20.8	$ 177.0	$ 212.1	$ 89.3	$ 76.3	$ 54.5	$ -	$ 630.7
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 306.2	$ 315.7	$ 326.7	$ 492.3	$ 527.3	$ 395.2	$ 391.5	$ 360.5	$ 315.3	$ 4,348.6
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	1.5	1,581.4	7,673.4	2,255.4	913.7	556.5	-	12,981.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 0.0	$ 38.5	$ 191.0	$ 57.5	$ 24.5	$ 18.0	$ -	$ 329.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ 0.0	$ 38.5	$ 191.0	$ 57.5	$ 24.5	$ 18.0	$ -	$ 329.6
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	-	3,216.7	6,619.9	20,505.7	47,435.1	21,470.2	246,384.7	354,932.5	244,902.8	31,789.3	97,931.5	18,818.3	1,094,006.7
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	30,054.1	26,409.8	32,335.7	47,591.8	78,241.7	85,389.4	314,021.1	416,209.9	266,912.8	62,973.5	127,674.5	55,735.6	1,543,549.9
Market Cost ($ x 1000)	$ -	$ 58.6	$ 132.7	$ 394.6	$ 880.5	$ 409.2	$ 5,006.0	$ 7,580.5	$ 5,330.5	$ 700.6	$ 2,706.7	$ 631.3	$ 23,831.2
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 1,548.9	$ 1,259.2	$ 1,114.7	$ 1,429.1	$ 2,055.7	$ 3,477.6	$ 8,592.8	$ 10,805.8	$ 6,480.2	$ 2,319.0	$ 4,560.1	$ 2,924.9	$ 46,568.1
Surplus Sales													
Energy (MWh)	455,799.7	290,548.9	247,421.8	147,538.8	80,512.0	177,137.8	1,963.5	426.9	2,854.0	74,832.9	18,034.3	101,644.3	1,598,715.0
Revenue Including Transmission Costs ($ x 1000)	$ 9,828.7	$ 5,233.0	$ 4,234.7	$ 2,267.6	$ 1,145.9	$ 2,549.5	$ 41.2	$ 17.1	$ 63.3	$ 1,704.6	$ 420.5	$ 2,642.6	$ 30,148.8
Transmission Costs ($ x 1000)	$ 455.8	$ 290.5	$ 247.4	$ 147.5	$ 80.5	$ 177.1	$ 2.0	$ 0.4	$ 2.9	$ 74.8	$ 18.0	$ 101.6	$ 1,598.7
Revenue Excluding Transmission Costs ($ x 1000)	$ 9,372.9	$ 4,942.5	$ 3,987.3	$ 2,120.0	$ 1,065.4	$ 2,372.3	$ 39.3	$ 16.7	$ 60.5	$ 1,629.8	$ 402.5	$ 2,541.0	$ 28,550.1
Net Power Supply Expense ($ x 1000)	$ 3,662.9	$ 2,844.9	$ 1,327.2	$ 3,254.8	$ 5,039.3	$ 5,362.4	$ 16,337.3	$ 19,068.3	$ 12,956.3	$ 8,441.8	$ 13,282.5	$ 12,997.8	$ 104,575.6

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
Hoku Annualized
1975

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	952,332.4	1,104,687.5	1,182,563.8	1,133,893.5	1,016,829.9	1,263,382.0	1,056,891.3	694,754.4	807,305.8	734,001.5	607,077.1	965,598.7	11,519,318.0
Bridger													
Energy (MWh)	470,567.9	405,421.9	415,122.8	322,900.7	295,186.0	286,346.5	444,294.6	436,174.6	380,740.3	419,835.6	454,809.7	468,976.5	4,800,377.2
Cost ($ x 1000)	$ 8,719.2	$ 7,518.7	$ 7,763.0	$ 6,061.5	$ 5,555.3	$ 5,422.3	$ 8,271.4	$ 8,110.5	$ 7,165.7	$ 7,854.6	$ 8,428.1	$ 8,692.1	$ 89,562.5
Boardman													
Energy (MWh)	26,720.9	24,241.7	27,582.9	3,119.4	-	11,613.2	32,712.4	34,700.3	32,673.0	32,655.2	29,263.2	26,469.7	281,751.8
Cost ($ x 1000)	$ 470.8	$ 426.8	$ 483.1	$ 53.2	$ -	$ 212.5	$ 556.3	$ 584.7	$ 552.9	$ 555.5	$ 504.2	$ 467.3	$ 4,867.5
Valmy													
Energy (MWh)	171,907.8	91,804.0	-	-	-	-	83,481.9	96,413.5	3,252.2	28,438.4	131,825.3	166,654.7	773,777.8
Cost ($ x 1000)	$ 4,393.2	$ 2,388.2	$ -	$ -	$ -	$ -	$ 2,175.7	$ 2,505.8	$ 85.8	$ 753.8	$ 3,419.1	$ 4,267.9	$ 19,989.4
Danskin													
Energy (MWh)	-	-	-	-	0.5	-	4,492.8	9,646.3	64.3	-	-	-	14,203.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ 0.0	$ -	$ 134.3	$ 296.3	$ 2.0	$ -	$ -	$ -	$ 432.7
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 449.6	$ 611.6	$ 308.0	$ 315.3	$ 305.9	$ 315.3	$ 4,150.5
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	1,052.0	7,287.6	-	-	-	-	8,339.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 31.7	$ 224.5	$ -	$ -	$ -	$ -	$ 256.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 31.7	$ 224.5	$ -	$ -	$ -	$ -	$ 256.1
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	-	107.8	-	-	9,192.0	3,290.4	29,998.5	206,885.4	50,714.4	5,438.7	14,917.2	7.8	320,552.1
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	30,054.1	23,300.9	25,715.8	27,086.1	39,998.6	67,209.5	97,634.9	268,162.8	72,724.4	36,622.9	44,660.2	36,925.1	770,095.3
Market Cost ($ x 1000)	$ -	$ 3.0	$ -	$ -	$ 203.7	$ 65.9	$ 847.8	$ 5,756.8	$ 1,368.5	$ 133.4	$ 478.6	$ 0.3	$ 8,858.0
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 1,548.9	$ 1,203.6	$ 981.9	$ 1,034.6	$ 1,378.8	$ 3,134.3	$ 4,434.6	$ 8,982.1	$ 2,518.2	$ 1,751.9	$ 2,332.0	$ 2,293.9	$ 31,594.9
Surplus Sales													
Energy (MWh)	275,431.1	494,194.7	520,913.8	437,269.6	137,317.9	275,971.6	95,934.2	11,310.9	90,861.2	137,838.3	107,140.5	263,332.5	2,847,516.2
Revenue Including Transmission Costs ($ x 1000)	$ 9,094.6	$ 11,491.3	$ 11,074.1	$ 8,738.6	$ 2,661.8	$ 4,455.2	$ 2,182.2	$ 279.6	$ 1,994.3	$ 3,202.2	$ 2,604.1	$ 7,236.4	$ 65,014.3
Transmission Costs ($ x 1000)	$ 275.4	$ 494.2	$ 520.9	$ 437.3	$ 137.3	$ 276.0	$ 95.9	$ 11.3	$ 90.9	$ 137.8	$ 107.1	$ 263.3	$ 2,847.5
Revenue Excluding Transmission Costs ($ x 1000)	$ 8,819.2	$ 10,997.2	$ 10,553.2	$ 8,301.4	$ 2,524.5	$ 4,179.2	$ 2,086.2	$ 268.3	$ 1,903.5	$ 3,064.4	$ 2,496.9	$ 6,973.0	$ 62,166.8
Net Power Supply Expense ($ x 1000)	$ 6,628.2	$ 827.4	$ (1,009.8)	$ (846.2)	$ 4,725.0	$ 4,895.8	$ 13,833.2	$ 20,750.9	$ 8,727.1	$ 8,166.7	$ 12,492.4	$ 9,063.4	$ 88,254.2

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
Hoku Annualized
1976

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,054,569.3	1,114,480.6	1,176,743.6	972,506.5	1,076,698.8	835,669.2	630,457.0	640,902.8	644,325.2	589,093.1	536,526.4	754,266.0	10,026,238.5
Bridger													
Energy (MWh)	467,569.7	399,246.7	442,750.1	332,297.2	304,456.3	348,051.1	458,178.2	455,633.2	395,549.2	451,926.6	455,557.1	470,742.4	4,981,957.9
Cost ($ x 1000)	$ 8,668.1	$ 7,424.7	$ 8,233.8	$ 6,233.0	$ 5,713.3	$ 6,535.3	$ 8,508.1	$ 8,464.7	$ 7,406.8	$ 8,401.5	$ 8,440.8	$ 8,722.2	$ 92,752.4
Boardman													
Energy (MWh)	22,175.6	19,611.0	27,356.2	1,453.1	-	24,321.1	33,467.4	32,940.7	30,610.3	34,639.9	35,632.4	36,942.1	299,149.8
Cost ($ x 1000)	$ 400.2	$ 360.7	$ 479.9	$ 26.0	$ -	$ 430.8	$ 567.1	$ 559.6	$ 523.5	$ 583.9	$ 595.1	$ 616.7	$ 5,143.6
Valmy													
Energy (MWh)	162,108.3	112,554.8	50,533.2	-	-	18,786.7	130,875.4	131,235.0	48,216.5	131,325.1	168,574.5	179,832.4	1,134,042.0
Cost ($ x 1000)	$ 4,159.4	$ 2,930.9	$ 1,328.2	$ -	$ -	$ 503.9	$ 3,392.7	$ 3,394.3	$ 1,259.9	$ 3,400.0	$ 4,304.3	$ 4,582.4	$ 29,256.0
Danskin													
Energy (MWh)	-	-	-	-	-	1.0	7,013.5	3,995.7	-	11.5	611.4	513.2	12,146.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 0.0	$ 232.0	$ 135.3	$ -	$ 0.4	$ 27.1	$ 27.3	$ 422.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 306.0	$ 547.3	$ 450.5	$ 305.9	$ 315.7	$ 333.1	$ 342.5	$ 4,140.0
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	164.5	1,983.7	-	-	192.9	20.0	2,361.1
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 5.5	$ 67.6	$ -	$ -	$ 8.6	$ 1.1	$ 82.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 5.5	$ 67.6	$ -	$ -	$ 8.6	$ 1.1	$ 82.8
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	3.9	-	-	-	4,739.1	97,104.1	296,963.2	217,481.1	97,763.9	5,303.7	42,064.1	32,631.5	794,054.6
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	30,057.9	23,193.1	25,715.8	27,086.1	35,545.7	161,023.2	364,599.6	278,758.5	119,773.8	36,487.9	71,807.2	69,548.8	1,243,597.8
Market Cost ($ x 1000)	$ 0.1	$ -	$ -	$ -	$ 116.3	$ 2,038.2	$ 8,362.4	$ 6,021.4	$ 2,502.2	$ 165.7	$ 1,723.8	$ 1,486.7	$ 22,416.7
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 1,549.0	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,291.4	$ 5,106.6	$ 11,949.2	$ 9,246.7	$ 3,651.8	$ 1,784.1	$ 3,577.3	$ 3,780.3	$ 45,153.5
Surplus Sales													
Energy (MWh)	360,328.7	513,824.8	593,027.3	283,612.8	202,003.6	35,272.8	129.9	9,621.1	32,576.4	129,769.0	108,406.9	110,572.6	2,379,145.9
Revenue Including Transmission Costs ($ x 1000)	$ 11,228.7	$ 11,490.1	$ 13,050.9	$ 5,446.2	$ 3,882.8	$ 808.0	$ 2.7	$ 236.0	$ 719.2	$ 3,258.9	$ 2,935.4	$ 3,455.7	$ 56,514.5
Transmission Costs ($ x 1000)	$ 360.3	$ 513.8	$ 593.0	$ 283.6	$ 202.0	$ 35.3	$ 0.1	$ 9.6	$ 32.6	$ 129.8	$ 108.4	$ 110.6	$ 2,379.1
Revenue Excluding Transmission Costs ($ x 1000)	$ 10,868.3	$ 10,976.2	$ 12,457.9	$ 5,162.6	$ 3,680.8	$ 772.7	$ 2.6	$ 226.4	$ 686.6	$ 3,129.1	$ 2,827.0	$ 3,345.2	$ 54,135.4
Net Power Supply Expense ($ x 1000)	$ 4,223.6	$ 1,228.1	$ (1,118.7)	$ 2,436.9	$ 3,639.2	$ 12,109.9	$ 24,967.3	$ 21,957.1	$ 12,461.3	$ 11,356.0	$ 14,432.2	$ 14,700.0	$ 122,392.9

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
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1977

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	644,281.6	644,883.1	718,788.8	514,881.8	575,481.2	504,357.2	480,935.5	493,463.3	339,285.9	413,597.5	406,291.8	557,403.6	6,293,651.3
Bridger													
Energy (MWh)	470,742.4	425,186.7	470,719.3	383,427.2	352,973.1	393,001.4	470,742.4	470,742.4	455,557.1	470,742.4	455,557.1	470,742.4	5,290,133.9
Cost ($ x 1000)	$ 8,722.2	$ 7,878.1	$ 8,721.8	$ 7,104.4	$ 6,540.2	$ 7,301.4	$ 8,722.2	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 98,038.5
Boardman													
Energy (MWh)	37,399.4	34,136.5	38,016.1	3,579.7	-	29,444.2	39,291.0	38,274.3	36,648.8	38,667.3	36,991.4	35,229.1	367,677.8
Cost ($ x 1000)	$ 623.2	$ 568.0	$ 632.0	$ 59.7	$ -	$ 503.9	$ 650.2	$ 635.7	$ 609.6	$ 641.3	$ 614.5	$ 592.3	$ 6,130.7
Valmy													
Energy (MWh)	180,348.9	162,895.8	179,542.6	150,402.2	150,703.9	164,876.8	180,348.9	180,348.9	174,531.2	180,278.6	174,531.2	180,348.8	2,059,158.0
Cost ($ x 1000)	$ 4,594.7	$ 4,150.1	$ 4,575.5	$ 3,833.9	$ 3,848.9	$ 4,216.0	$ 4,594.7	$ 4,594.7	$ 4,446.5	$ 4,593.0	$ 4,446.5	$ 4,594.7	$ 52,489.2
Danskin													
Energy (MWh)	-	-	-	-	-	90.8	42,756.0	23,978.5	5,152.7	3,363.0	863.0	-	76,204.0
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 4.6	$ 2,192.7	$ 1,260.5	$ 277.6	$ 191.1	$ 59.9	$ -	$ 3,986.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 310.6	$ 2,507.9	$ 1,575.8	$ 583.5	$ 506.3	$ 365.8	$ 315.3	$ 7,704.2
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	15,517.2	12,576.9	366.0	551.3	13.3	-	29,024.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 801.6	$ 665.3	$ 19.9	$ 31.6	$ 0.9	$ -	$ 1,519.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 801.6	$ 665.3	$ 19.9	$ 31.6	$ 0.9	$ -	$ 1,519.2
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	34,153.5	80.3	-	34,827.9	175,642.5	202,917.1	328,161.7	260,600.2	218,998.4	59,528.9	111,186.5	143,645.9	1,569,743.0
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.3
Total Energy Excl. CSPP (MWh)	64,207.6	23,273.4	25,715.8	61,914.1	206,449.2	266,836.3	395,798.0	321,877.6	241,008.4	90,713.1	140,929.6	180,563.2	2,019,286.2
Market Cost ($ x 1000)	$ 2,338.3	$ 4.7	$ -	$ 1,552.8	$ 7,213.7	$ 7,694.2	$ 26,223.6	$ 14,152.9	$ 11,044.6	$ 3,248.9	$ 6,866.7	$ 8,779.1	$ 89,119.6
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 3,887.2	$ 1,205.4	$ 981.9	$ 2,587.4	$ 8,388.8	$ 10,762.6	$ 29,810.5	$ 17,378.2	$ 12,194.3	$ 4,867.3	$ 8,720.2	$ 11,072.7	$ 111,856.5
Surplus Sales													
Energy (MWh)	20,827.9	135,114.0	302,711.1	64,474.9	70,910.3	6,027.2	763.4	5,433.2	46,651.4	84,197.9	54,682.3	22,994.8	814,788.4
Revenue Including Transmission Costs ($ x 1000)	$ 1,278.1	$ 6,391.0	$ 11,927.5	$ 2,093.1	$ 1,656.6	$ 140.1	$ 24.8	$ 162.9	$ 1,409.1	$ 2,831.5	$ 2,158.7	$ 860.5	$ 30,934.0
Transmission Costs ($ x 1000)	$ 20.8	$ 135.1	$ 302.7	$ 64.5	$ 70.9	$ 6.0	$ 0.8	$ 5.4	$ 46.7	$ 84.2	$ 54.7	$ 23.0	$ 814.8
Revenue Excluding Transmission Costs ($ x 1000)	$ 1,257.3	$ 6,255.9	$ 11,624.8	$ 2,028.7	$ 1,585.7	$ 134.1	$ 24.0	$ 157.5	$ 1,362.4	$ 2,747.3	$ 2,104.1	$ 837.5	$ 30,119.2
Net Power Supply Expense ($ x 1000)	$ 16,885.2	$ 7,833.0	$ 3,601.7	$ 11,862.7	$ 17,507.5	$ 22,960.3	$ 47,063.1	$ 33,414.4	$ 24,932.2	$ 16,614.5	$ 20,484.7	$ 24,459.6	$ 247,619.1

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
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1978

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	563,754.5	740,648.2	741,054.6	866,686.6	926,813.3	930,172.5	683,515.0	560,341.2	544,853.1	571,062.8	514,567.2	751,269.0	8,394,738.0
Bridger													
Energy (MWh)	470,742.4	424,939.0	469,729.7	374,797.6	339,358.8	370,742.4	470,015.0	469,813.8	453,088.8	469,822.6	455,557.1	470,742.4	5,239,349.5
Cost ($ x 1000)	$ 8,722.2	$ 7,873.9	$ 8,704.9	$ 6,957.3	$ 6,308.2	$ 6,922.0	$ 8,709.8	$ 8,706.4	$ 8,398.8	$ 8,706.5	$ 8,440.8	$ 8,722.2	$ 97,173.0
Boardman													
Energy (MWh)	29,955.8	26,634.8	33,002.4	2,758.4	-	26,024.1	36,306.7	35,832.4	35,170.6	35,616.1	32,730.3	33,810.3	327,842.1
Cost ($ x 1000)	$ 517.0	$ 461.0	$ 560.5	$ 48.0	$ -	$ 452.2	$ 607.6	$ 600.9	$ 588.5	$ 597.8	$ 553.7	$ 572.0	$ 5,559.3
Valmy													
Energy (MWh)	179,523.6	156,403.8	173,398.8	114,996.0	119,101.2	126,073.5	178,557.9	179,500.7	165,695.3	179,152.2	174,020.5	180,337.6	1,926,761.0
Cost ($ x 1000)	$ 4,575.0	$ 3,995.1	$ 4,428.7	$ 2,973.2	$ 3,076.5	$ 3,265.0	$ 4,552.0	$ 4,574.5	$ 4,235.5	$ 4,566.1	$ 4,434.3	$ 4,594.4	$ 49,270.2
Danskin													
Energy (MWh)	-	-	-	-	-	-	13,726.6	11,715.7	336.0	-	-	-	25,778.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 544.8	$ 476.6	$ 14.0	$ -	$ -	$ -	$ 1,035.5
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 860.1	$ 791.9	$ 319.9	$ 315.3	$ 305.9	$ 315.3	$ 4,753.4
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	2,212.0	6,810.7	1.4	-	-	-	9,024.0
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 88.4	$ 278.7	$ 0.1	$ -	$ -	$ -	$ 367.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 88.4	$ 278.7	$ 0.1	$ -	$ -	$ -	$ 367.2
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	107,175.4	-	-	-	4,740.6	20,160.2	191,974.1	224,778.0	84,910.6	7,144.5	53,387.3	32,905.5	727,176.2
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	137,229.5	23,193.1	25,715.8	27,086.1	35,547.2	84,079.3	259,610.4	286,055.5	106,920.6	38,328.7	83,130.3	69,822.8	1,176,719.4
Market Cost ($ x 1000)	$ 4,776.7	$ -	$ -	$ -	$ 136.2	$ 446.9	$ 7,682.3	$ 8,621.7	$ 3,244.4	$ 277.2	$ 2,371.1	$ 1,620.2	$ 29,176.7
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 6,325.6	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,311.3	$ 3,515.3	$ 11,269.1	$ 11,847.1	$ 4,394.0	$ 1,895.6	$ 4,224.6	$ 3,913.8	$ 51,913.6
Surplus Sales													
Energy (MWh)	5,053.7	216,557.5	312,829.7	336,594.5	206,123.4	184,512.3	19,317.9	14,241.4	100,167.0	180,267.3	99,510.4	104,689.9	1,779,865.0
Revenue Including Transmission Costs ($ x 1000)	$ 216.3	$ 6,952.8	$ 9,162.9	$ 7,880.0	$ 5,133.0	$ 4,820.2	$ 469.2	$ 364.5	$ 2,581.7	$ 5,028.9	$ 2,814.8	$ 3,468.4	$ 48,892.7
Transmission Costs ($ x 1000)	$ 5.1	$ 216.6	$ 312.8	$ 336.6	$ 206.1	$ 184.5	$ 19.3	$ 14.2	$ 100.2	$ 180.3	$ 99.5	$ 104.7	$ 1,779.9
Revenue Excluding Transmission Costs ($ x 1000)	$ 211.2	$ 6,736.3	$ 8,850.1	$ 7,543.4	$ 4,926.9	$ 4,635.7	$ 449.9	$ 350.2	$ 2,481.5	$ 4,848.7	$ 2,715.3	$ 3,363.7	$ 47,112.8
Net Power Supply Expense ($ x 1000)	$ 20,243.8	$ 7,081.6	$ 6,141.2	$ 3,775.6	$ 6,084.4	$ 9,824.8	$ 25,637.2	$ 26,449.1	$ 15,455.3	$ 11,232.6	$ 15,244.1	$ 14,754.0	$ 161,923.8

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
Hoku Annualized
1979

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	873,588.0	903,966.4	980,480.1	901,909.1	1,082,002.9	705,325.3	538,839.3	543,635.5	392,712.7	480,649.7	413,379.6	600,582.5	8,417,071.0
Bridger													
Energy (MWh)	470,742.4	425,186.7	470,611.5	382,727.1	338,908.0	376,116.4	470,742.4	470,698.9	454,910.1	470,730.6	455,557.1	470,742.4	5,257,673.5
Cost ($ x 1000)	$ 8,722.2	$ 7,878.1	$ 8,720.0	$ 7,092.4	$ 6,300.5	$ 7,013.6	$ 8,722.2	$ 8,721.5	$ 8,429.8	$ 8,722.0	$ 8,440.8	$ 8,722.2	$ 97,485.3
Boardman													
Energy (MWh)	33,792.4	32,925.2	36,610.6	3,424.0	-	27,999.4	37,775.6	37,101.1	35,738.5	37,190.7	36,378.7	37,495.5	356,431.7
Cost ($ x 1000)	$ 571.8	$ 550.7	$ 612.0	$ 57.5	$ -	$ 483.3	$ 628.6	$ 619.0	$ 596.6	$ 620.3	$ 605.8	$ 624.6	$ 5,970.2
Valmy													
Energy (MWh)	180,196.2	162,776.3	171,590.5	142,565.3	126,006.9	142,213.1	180,245.5	180,180.7	174,487.9	180,285.9	174,531.2	180,348.9	1,995,428.6
Cost ($ x 1000)	$ 4,591.1	$ 4,147.2	$ 4,385.7	$ 3,646.8	$ 3,255.3	$ 3,670.8	$ 4,592.2	$ 4,590.7	$ 4,445.5	$ 4,593.2	$ 4,446.5	$ 4,594.7	$ 50,959.7
Danskin													
Energy (MWh)	-	-	-	-	-	0.0	30,606.5	16,281.0	2,892.2	611.2	1,269.6	240.3	51,900.8
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 0.0	$ 1,297.3	$ 707.4	$ 128.7	$ 28.7	$ 72.6	$ 16.5	$ 2,251.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 1,612.6	$ 1,022.7	$ 434.6	$ 343.9	$ 378.5	$ 331.8	$ 5,969.0
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	8,606.2	6,912.0	180.2	40.9	82.3	-	15,821.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 367.4	$ 302.1	$ 8.1	$ 1.9	$ 4.7	$ -	$ 684.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 367.4	$ 302.1	$ 8.1	$ 1.9	$ 4.7	$ -	$ 684.3
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	124.1	-	-	-	170.3	84,836.7	292,577.4	230,836.1	181,845.5	28,997.8	106,172.8	110,267.9	1,035,828.7
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	30,178.2	23,193.1	25,715.8	27,086.1	30,976.9	148,755.9	360,213.7	292,113.6	203,855.5	60,182.0	135,915.9	147,185.3	1,485,371.9
Market Cost ($ x 1000)	$ 4.5	$ -	$ -	$ -	$ 5.0	$ 2,642.1	$ 17,716.6	$ 9,989.9	$ 7,418.3	$ 1,260.7	$ 5,409.3	$ 6,402.1	$ 50,848.7
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 1,553.4	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,180.2	$ 5,710.5	$ 21,303.5	$ 13,215.3	$ 8,568.0	$ 2,879.2	$ 7,262.8	$ 8,695.7	$ 73,585.6
Surplus Sales													
Energy (MWh)	212,345.1	392,786.2	554,936.8	407,981.6	363,197.6	47,830.6	2,403.6	11,094.1	58,878.3	115,975.9	56,619.3	35,302.7	2,259,351.7
Revenue Including Transmission Costs ($ x 1000)	$ 10,690.6	$ 14,748.4	$ 17,446.2	$ 10,919.6	$ 9,113.8	$ 1,245.0	$ 63.9	$ 288.6	$ 1,508.4	$ 3,291.8	$ 1,822.3	$ 1,275.5	$ 72,413.9
Transmission Costs ($ x 1000)	$ 212.3	$ 392.8	$ 554.9	$ 408.0	$ 363.2	$ 47.8	$ 2.4	$ 11.1	$ 58.9	$ 116.0	$ 56.6	$ 35.3	$ 2,259.4
Revenue Excluding Transmission Costs ($ x 1000)	$ 10,478.2	$ 14,355.6	$ 16,891.2	$ 10,511.6	$ 8,750.6	$ 1,197.1	$ 61.5	$ 277.5	$ 1,449.5	$ 3,175.8	$ 1,765.7	$ 1,240.2	$ 70,154.6
Net Power Supply Expense ($ x 1000)	$ 5,275.4	$ (291.6)	$ (1,876.4)	$ 1,625.7	$ 2,300.7	$ 15,987.0	$ 37,165.1	$ 28,193.6	$ 21,033.1	$ 13,984.6	$ 19,373.5	$ 21,728.8	$ 164,499.4

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
Hoku Annualized
1980

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	795,474.2	1,002,337.5	646,601.8	1,170,174.5	1,071,480.4	1,191,777.0	643,205.6	590,740.9	544,744.5	496,489.0	468,465.6	826,832.5	9,448,323.6
Bridger													
Energy (MWh)	470,709.7	424,789.1	469,452.3	355,214.5	318,580.5	362,819.7	468,709.1	468,526.4	446,675.1	467,049.4	455,557.1	470,742.4	5,178,825.3
Cost ($ x 1000)	$ 8,721.6	$ 7,871.3	$ 8,700.2	$ 6,623.5	$ 5,954.1	$ 6,787.0	$ 8,687.5	$ 8,684.4	$ 8,289.5	$ 8,659.3	$ 8,440.8	$ 8,722.2	$ 96,141.5
Boardman													
Energy (MWh)	29,807.9	30,002.5	32,963.8	3,008.8	-	24,220.1	37,174.0	36,054.1	34,752.4	36,874.4	35,740.9	34,997.6	335,596.5
Cost ($ x 1000)	$ 514.9	$ 509.0	$ 559.9	$ 51.6	$ -	$ 423.6	$ 620.0	$ 604.0	$ 582.6	$ 615.7	$ 596.7	$ 589.0	$ 5,667.1
Valmy													
Energy (MWh)	178,242.0	154,041.3	142,431.7	28,568.8	61,609.4	69,218.1	155,961.2	154,251.9	132,588.6	157,272.4	174,279.7	180,165.7	1,588,630.8
Cost ($ x 1000)	$ 4,544.4	$ 3,934.0	$ 3,679.5	$ 753.5	$ 1,604.4	$ 1,809.3	$ 4,008.1	$ 3,962.6	$ 3,427.1	$ 4,044.2	$ 4,440.5	$ 4,590.3	$ 40,798.0
Danskin													
Energy (MWh)	-	-	-	-	-	-	25,526.5	12,744.1	283.4	104.4	731.2	-	39,389.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 919.5	$ 471.0	$ 10.7	$ 4.2	$ 35.4	$ -	$ 1,440.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 1,234.8	$ 786.2	$ 316.7	$ 319.4	$ 341.3	$ 315.3	$ 5,158.6
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	9,218.8	8,687.8	-	-	28.5	-	17,935.1
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 334.5	$ 322.5	$ -	$ -	$ 1.4	$ -	$ 658.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 334.5	$ 322.5	$ -	$ -	$ 1.4	$ -	$ 658.4
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	344.0	-	3,520.5	-	2,078.0	746.1	220,202.0	212,123.0	85,125.2	22,916.9	76,052.0	11,299.2	634,406.9
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	30,398.1	23,193.1	29,236.4	27,086.1	32,884.6	64,665.3	287,838.3	273,400.5	107,135.2	54,101.1	105,795.0	48,216.5	1,083,950.1
Market Cost ($ x 1000)	$ 7.3	$ -	$ 113.4	$ -	$ 53.3	$ 17.2	$ 11,156.7	$ 7,673.5	$ 2,836.8	$ 828.1	$ 3,297.5	$ 525.1	$ 26,509.0
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 1,556.1	$ 1,200.7	$ 1,095.4	$ 1,034.6	$ 1,228.5	$ 3,085.6	$ 14,743.6	$ 10,898.8	$ 3,986.5	$ 2,446.5	$ 5,150.9	$ 2,818.7	$ 49,245.8
Surplus Sales													
Energy (MWh)	128,479.7	479,102.2	190,614.4	534,322.6	269,857.8	360,120.6	3,007.9	8,577.2	60,280.3	98,175.5	80,102.9	159,662.4	2,372,303.6
Revenue Including Transmission Costs ($ x 1000)	$ 5,243.5	$ 14,284.3	$ 5,168.3	$ 11,334.6	$ 6,008.0	$ 7,915.9	$ 73.0	$ 225.3	$ 1,456.5	$ 2,554.8	$ 2,277.1	$ 5,388.1	$ 61,929.5
Transmission Costs ($ x 1000)	$ 128.5	$ 479.1	$ 190.6	$ 534.3	$ 269.9	$ 360.1	$ 3.0	$ 8.6	$ 60.3	$ 98.2	$ 80.1	$ 159.7	$ 2,372.3
Revenue Excluding Transmission Costs ($ x 1000)	$ 5,115.0	$ 13,805.2	$ 4,977.7	$ 10,800.3	$ 5,738.2	$ 7,555.8	$ 70.0	$ 216.8	$ 1,396.2	$ 2,456.6	$ 2,197.0	$ 5,228.5	$ 59,557.2
Net Power Supply Expense ($ x 1000)	$ 10,537.3	$ (2.9)	$ 9,372.6	$ (2,031.1)	$ 3,364.1	$ 4,855.6	$ 29,558.5	$ 25,041.9	$ 15,206.1	$ 13,628.5	$ 16,774.7	$ 11,807.0	$ 138,112.2

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
Hoku Annualized
1981

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	808,822.6	1,002,247.1	812,624.7	776,299.4	840,068.9	1,039,805.8	563,028.8	551,998.7	450,744.9	505,751.2	412,451.7	764,977.9	8,528,821.8
Bridger													
Energy (MWh)	470,742.4	424,785.6	468,849.9	373,597.9	336,836.1	367,707.8	470,004.7	470,419.2	450,362.8	470,742.4	455,557.1	470,742.4	5,230,348.2
Cost ($ x 1000)	$ 8,722.2	$ 7,871.3	$ 8,689.9	$ 6,936.8	$ 6,265.2	$ 6,870.3	$ 8,709.6	$ 8,716.7	$ 8,352.3	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 97,019.6
Boardman													
Energy (MWh)	28,664.9	27,563.4	30,030.2	2,749.5	-	26,357.4	35,879.1	37,519.7	34,879.6	36,900.2	35,933.3	37,164.5	333,641.8
Cost ($ x 1000)	$ 498.6	$ 474.2	$ 518.1	$ 47.9	$ -	$ 459.9	$ 601.5	$ 625.0	$ 584.4	$ 616.1	$ 599.4	$ 619.9	$ 5,644.9
Valmy													
Energy (MWh)	177,352.6	149,774.9	167,702.0	118,701.7	108,556.3	121,565.6	176,732.8	180,253.8	160,588.2	179,474.3	174,478.2	180,348.9	1,895,529.4
Cost ($ x 1000)	$ 4,523.2	$ 3,832.2	$ 4,292.8	$ 3,068.1	$ 2,811.6	$ 3,148.2	$ 4,508.4	$ 4,592.4	$ 4,113.7	$ 4,573.8	$ 4,445.2	$ 4,594.7	$ 48,504.3
Danskin													
Energy (MWh)	-	-	-	-	-	-	18,196.6	21,110.3	117.1	366.2	1,605.9	-	41,396.1
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 722.3	$ 860.6	$ 4.9	$ 16.1	$ 85.8	$ -	$ 1,689.7
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 1,037.5	$ 1,175.9	$ 310.8	$ 331.3	$ 391.8	$ 315.3	$ 5,407.5
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	3,480.9	17,455.5	-	16.3	51.6	-	21,004.4
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 139.2	$ 714.3	$ -	$ 0.7	$ 2.8	$ -	$ 857.0
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 139.2	$ 714.3	$ -	$ 0.7	$ 2.8	$ -	$ 857.0
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	678.5	-	-	187.4	27,633.2	16,279.5	292,244.1	208,659.5	142,170.8	18,749.1	107,755.7	24,069.2	838,427.1
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	30,732.6	23,193.1	25,715.8	27,273.6	58,439.8	80,198.7	359,880.4	269,937.0	164,180.8	49,933.3	137,498.7	60,986.5	1,287,970.3
Market Cost ($ x 1000)	$ 13.5	$ -	$ -	$ 3.7	$ 789.1	$ 475.2	$ 11,799.9	$ 9,409.8	$ 5,241.1	$ 750.3	$ 5,090.7	$ 1,305.5	$ 34,878.8
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 1,562.4	$ 1,200.7	$ 981.9	$ 1,038.3	$ 1,964.2	$ 3,543.5	$ 15,386.7	$ 12,635.1	$ 6,390.8	$ 2,368.8	$ 6,944.2	$ 3,599.1	$ 57,615.7
Surplus Sales													
Energy (MWh)	140,163.0	472,302.6	374,851.0	248,891.9	129,204.0	283,055.8	2,577.6	12,865.6	54,974.7	129,468.8	57,081.5	112,928.1	2,018,364.5
Revenue Including Transmission Costs ($ x 1000)	$ 6,006.6	$ 14,517.3	$ 10,404.0	$ 6,173.8	$ 2,703.5	$ 7,053.2	$ 62.4	$ 337.5	$ 1,366.2	$ 3,595.3	$ 1,729.3	$ 4,334.9	$ 58,284.0
Transmission Costs ($ x 1000)	$ 140.2	$ 472.3	$ 374.9	$ 248.9	$ 129.2	$ 283.1	$ 2.6	$ 12.9	$ 55.0	$ 129.5	$ 57.1	$ 112.9	$ 2,018.4
Revenue Excluding Transmission Costs ($ x 1000)	$ 5,866.5	$ 14,045.0	$ 10,029.1	$ 5,924.9	$ 2,574.3	$ 6,770.1	$ 59.8	$ 324.6	$ 1,311.2	$ 3,465.9	$ 1,672.3	$ 4,222.0	$ 56,265.7
Net Power Supply Expense ($ x 1000)	$ 9,755.1	$ (379.3)	$ 4,768.9	$ 5,472.1	$ 8,782.0	$ 7,557.7	$ 30,323.1	$ 28,134.7	$ 18,440.8	$ 13,147.1	$ 19,152.0	$ 13,629.2	$ 158,783.3

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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	977,114.6	1,024,124.0	1,131,975.3	967,534.9	1,114,722.6	1,266,875.2	1,234,041.3	723,407.8	926,995.8	784,880.5	688,219.8	1,040,986.8	11,880,878.6
Bridger													
Energy (MWh)	467,090.6	314,955.4	282,778.8	258,423.2	219,387.9	229,214.7	365,483.1	373,256.9	329,217.5	382,679.1	427,049.4	470,721.7	4,120,258.2
Cost ($ x 1000)	$ 8,660.0	$ 5,916.7	$ 5,350.5	$ 4,897.1	$ 4,162.7	$ 4,361.4	$ 6,871.9	$ 7,021.3	$ 6,225.6	$ 7,210.0	$ 7,943.7	$ 8,721.8	$ 77,342.6
Boardman													
Energy (MWh)	21,480.8	12,829.0	20,556.7	2,324.5	-	4,481.2	29,325.1	30,896.4	32,601.2	36,379.8	32,098.5	34,598.0	257,571.3
Cost ($ x 1000)	$ 396.1	$ 248.5	$ 374.2	$ 41.8	$ -	$ 84.9	$ 501.6	$ 527.5	$ 551.9	$ 608.7	$ 544.7	$ 583.3	$ 4,463.2
Valmy													
Energy (MWh)	153,952.8	-	-	-	-	-	31,337.9	25,656.9	4,395.8	-	60,148.8	145,406.2	420,898.4
Cost ($ x 1000)	$ 3,961.5	$ -	$ -	$ -	$ -	$ -	$ 846.2	$ 702.9	$ 123.7	$ -	$ 1,590.2	$ 3,756.3	$ 10,980.8
Danskin													
Energy (MWh)	-	-	-	0.6	0.8	106.8	7,613.3	8,269.7	2,468.2	595.2	79.6	-	19,134.2
Cost ($ x 1000)	$ -	$ -	$ -	$ 0.0	$ 0.0	$ 2.8	$ 199.7	$ 222.0	$ 67.9	$ 17.2	$ 2.8	$ -	$ 512.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 306.0	$ 315.3	$ 308.7	$ 514.9	$ 537.3	$ 373.8	$ 332.5	$ 308.7	$ 315.3	$ 4,230.2
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	1,748.3	6,633.0	1,625.3	300.5	-	-	10,307.1
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 46.2	$ 179.1	$ 45.0	$ 8.7	$ -	$ -	$ 279.0
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 46.2	$ 179.1	$ 45.0	$ 8.7	$ -	$ -	$ 279.0
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	23.6	13,176.8	2,812.8	7,712.0	8,667.2	10,948.1	23,924.3	312,156.8	35,219.0	8,677.0	16,674.5	-	439,992.1
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	30,077.7	36,369.9	28,528.6	34,798.1	39,473.8	74,867.2	91,560.7	373,434.3	57,228.9	39,861.2	46,417.6	36,917.3	889,535.2
Market Cost ($ x 1000)	$ 0.4	$ 248.9	$ 59.5	$ 160.5	$ 150.4	$ 214.3	$ 513.7	$ 7,001.4	$ 844.3	$ 200.4	$ 461.2	$ -	$ 9,855.0
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 1,549.3	$ 1,449.6	$ 1,041.4	$ 1,195.0	$ 1,325.5	$ 3,282.7	$ 4,100.6	$ 10,226.7	$ 1,994.0	$ 1,818.8	$ 2,314.6	$ 2,293.6	$ 32,591.9
Surplus Sales													
Energy (MWh)	273,564.4	233,016.9	333,767.8	213,351.1	158,888.0	222,965.5	136,483.8	5,726.4	148,634.0	130,981.1	93,518.6	327,337.8	2,278,235.5
Revenue Including Transmission Costs ($ x 1000)	$ 7,370.5	$ 4,436.6	$ 6,377.2	$ 3,792.7	$ 2,527.7	$ 3,440.3	$ 2,920.7	$ 137.9	$ 2,977.9	$ 2,971.9	$ 2,277.1	$ 9,360.0	$ 48,590.5
Transmission Costs ($ x 1000)	$ 273.6	$ 233.0	$ 333.8	$ 213.4	$ 158.9	$ 223.0	$ 136.5	$ 5.7	$ 148.6	$ 131.0	$ 93.5	$ 327.3	$ 2,278.2
Revenue Excluding Transmission Costs ($ x 1000)	$ 7,097.0	$ 4,203.5	$ 6,043.4	$ 3,579.4	$ 2,368.8	$ 3,217.3	$ 2,784.2	$ 132.2	$ 2,829.3	$ 2,840.9	$ 2,183.6	$ 9,032.6	$ 46,312.3
Net Power Supply Expense ($ x 1000)	$ 7,785.1	$ 3,698.6	$ 1,037.9	$ 2,860.5	$ 3,434.7	$ 4,820.4	$ 10,097.1	$ 19,062.7	$ 6,484.7	$ 7,137.8	$ 10,518.3	$ 6,637.6	$ 83,575.4

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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,203,539.1	1,106,229.0	1,183,069.9	1,116,402.9	1,227,659.8	1,244,438.1	1,154,280.3	771,751.6	931,093.1	926,244.0	643,002.3	1,102,796.6	12,610,506.6
Bridger													
Energy (MWh)	458,160.0	361,434.8	392,101.6	235,948.6	261,598.7	294,728.2	423,490.7	417,531.4	359,000.6	410,679.9	449,621.7	470,742.4	4,535,038.5
Cost ($ x 1000)	$ 8,507.8	$ 6,769.0	$ 7,367.8	$ 4,461.2	$ 4,935.0	$ 5,567.0	$ 7,905.6	$ 7,792.8	$ 6,758.6	$ 7,698.5	$ 8,339.7	$ 8,722.2	$ 84,825.1
Boardman													
Energy (MWh)	19,956.4	14,738.0	23,727.0	1,592.9	-	16,515.6	33,202.1	32,539.5	32,454.4	33,632.5	32,969.7	35,485.2	276,813.3
Cost ($ x 1000)	$ 368.5	$ 281.3	$ 425.2	$ 28.7	$ -	$ 297.4	$ 563.3	$ 553.9	$ 549.8	$ 569.5	$ 557.1	$ 595.9	$ 4,790.8
Valmy													
Energy (MWh)	149,601.5	13,405.8	-	-	-	-	53,886.2	52,460.6	5,235.1	-	123,072.9	161,206.2	558,868.2
Cost ($ x 1000)	$ 3,856.3	$ 371.7	$ -	$ -	$ -	$ -	$ 1,417.2	$ 1,400.0	$ 143.7	$ -	$ 3,192.5	$ 4,138.0	$ 14,519.3
Danskin													
Energy (MWh)	-	-	-	17.9	0.3	-	7,197.7	6,104.3	934.2	0.6	102.2	-	14,357.1
Cost ($ x 1000)	$ -	$ -	$ -	$ 0.5	$ 0.0	$ -	$ 204.1	$ 177.2	$ 27.8	$ 0.0	$ 3.9	$ -	$ 413.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 306.4	$ 315.3	$ 305.9	$ 519.3	$ 492.5	$ 333.7	$ 315.3	$ 309.8	$ 315.3	$ 4,131.3
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	2,007.5	4,543.1	550.3	-	-	-	7,100.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 57.3	$ 132.6	$ 16.5	$ -	$ -	$ -	$ 206.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 57.3	$ 132.6	$ 16.5	$ -	$ -	$ -	$ 206.4
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	-	260.2	273.7	613.5	1,709.7	2,240.4	21,118.1	207,939.6	26,348.9	-	20,180.4	-	280,684.4
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	30,054.1	23,453.3	25,989.5	27,699.6	32,516.3	66,159.5	88,754.4	269,217.0	48,358.9	31,184.2	49,923.5	36,917.3	730,227.6
Market Cost ($ x 1000)	$ -	$ 5.4	$ 6.2	$ 12.3	$ 36.9	$ 46.5	$ 573.1	$ 4,963.9	$ 689.8	$ -	$ 652.4	$ -	$ 6,986.6
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 1,548.9	$ 1,206.0	$ 988.2	$ 1,046.9	$ 1,212.0	$ 3,114.9	$ 4,160.0	$ 8,189.2	$ 1,839.5	$ 1,618.4	$ 2,505.9	$ 2,293.6	$ 29,723.5
Surplus Sales													
Energy (MWh)	485,159.0	363,999.4	494,816.4	331,931.7	307,077.9	269,261.8	138,193.2	18,318.9	171,727.8	288,026.0	138,197.3	405,855.5	3,412,564.8
Revenue Including Transmission Costs ($ x 1000)	$ 12,796.8	$ 7,269.8	$ 9,777.1	$ 5,830.8	$ 5,009.1	$ 4,557.5	$ 3,107.5	$ 418.2	$ 3,595.8	$ 6,443.6	$ 3,485.3	$ 12,319.1	$ 74,610.7
Transmission Costs ($ x 1000)	$ 485.2	$ 364.0	$ 494.8	$ 331.9	$ 307.1	$ 269.3	$ 138.2	$ 18.3	$ 171.7	$ 288.0	$ 138.2	$ 405.9	$ 3,412.6
Revenue Excluding Transmission Costs ($ x 1000)	$ 12,311.7	$ 6,905.8	$ 9,282.3	$ 5,498.9	$ 4,702.0	$ 4,288.2	$ 2,969.3	$ 399.8	$ 3,424.0	$ 6,155.6	$ 3,347.1	$ 11,913.3	$ 71,198.1
Net Power Supply Expense ($ x 1000)	$ 2,285.1	$ 2,009.6	$ (185.9)	$ 344.4	$ 1,760.2	$ 4,997.1	$ 11,653.4	$ 18,161.1	$ 6,217.7	$ 4,046.1	$ 11,557.9	$ 4,151.7	$ 66,998.3

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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,198,830.9	1,112,253.8	1,201,641.9	1,100,222.4	1,237,697.4	1,227,553.9	1,083,238.0	791,410.8	965,650.0	783,565.6	691,610.2	988,481.4	12,382,156.3
Bridger													
Energy (MWh)	469,916.0	403,885.6	433,797.4	335,391.0	293,355.3	327,741.7	439,205.4	440,547.4	391,694.5	429,302.6	455,232.9	470,742.4	4,890,812.0
Cost ($ x 1000)	$ 8,708.1	$ 7,492.5	$ 8,081.3	$ 6,274.4	$ 5,515.7	$ 6,177.9	$ 8,173.4	$ 8,196.3	$ 7,352.4	$ 8,015.9	$ 8,435.3	$ 8,722.2	$ 91,145.4
Boardman													
Energy (MWh)	26,206.0	21,548.2	27,771.7	2,917.3	-	22,467.3	33,527.7	33,537.6	31,984.7	35,479.1	33,054.5	36,166.7	304,660.7
Cost ($ x 1000)	$ 463.5	$ 388.4	$ 485.8	$ 50.3	$ -	$ 397.9	$ 568.0	$ 568.1	$ 543.1	$ 595.8	$ 558.3	$ 605.6	$ 5,224.9
Valmy													
Energy (MWh)	167,707.7	98,365.0	-	-	-	-	111,653.5	107,074.5	9,202.3	72,859.6	149,599.9	180,077.8	896,540.1
Cost ($ x 1000)	$ 4,293.0	$ 2,561.1	$ -	$ -	$ -	$ -	$ 2,901.4	$ 2,779.2	$ 246.8	$ 1,890.1	$ 3,850.2	$ 4,588.2	$ 23,110.1
Danskin													
Energy (MWh)	-	-	-	-	-	-	3,589.6	4,139.4	2.3	-	1.8	-	7,733.1
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 112.3	$ 132.7	$ 0.1	$ -	$ 0.1	$ -	$ 245.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 427.6	$ 448.0	$ 306.0	$ 315.3	$ 306.0	$ 315.3	$ 3,963.0
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	229.9	3,628.7	-	-	-	-	3,858.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 7.2	$ 117.0	$ -	$ -	$ -	$ -	$ 124.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 7.2	$ 117.0	$ -	$ -	$ -	$ -	$ 124.2
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	-	225.0	-	-	1,309.7	2,322.3	20,388.7	124,511.5	14,463.8	1,058.4	192.1	-	164,471.5
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	30,054.1	23,418.1	25,715.8	27,086.1	32,116.3	66,241.5	88,025.0	185,789.0	36,473.7	32,242.6	29,935.1	36,917.3	614,014.7
Market Cost ($ x 1000)	$ -	$ 6.1	$ -	$ -	$ 31.2	$ 54.1	$ 601.1	$ 3,230.1	$ 387.5	$ 27.8	$ 7.3	$ -	$ 4,345.2
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 1,548.9	$ 1,206.7	$ 981.9	$ 1,034.6	$ 1,206.4	$ 3,122.5	$ 4,187.9	$ 6,455.4	$ 1,537.2	$ 1,646.3	$ 1,860.7	$ 2,293.6	$ 27,082.1
Surplus Sales													
Energy (MWh)	516,562.6	504,209.2	558,855.1	415,886.6	348,471.9	291,424.8	134,843.4	30,298.8	229,108.6	239,734.2	198,939.3	311,093.4	3,779,427.9
Revenue Including Transmission Costs ($ x 1000)	$ 16,236.0	$ 11,593.0	$ 12,270.0	$ 8,301.5	$ 6,016.4	$ 5,375.1	$ 3,140.3	$ 747.3	$ 4,865.1	$ 6,068.8	$ 5,556.7	$ 10,169.0	$ 90,339.3
Transmission Costs ($ x 1000)	$ 516.6	$ 504.2	$ 558.9	$ 415.9	$ 348.5	$ 291.4	$ 134.8	$ 30.3	$ 229.1	$ 239.7	$ 198.9	$ 311.1	$ 3,779.4
Revenue Excluding Transmission Costs ($ x 1000)	$ 15,719.4	$ 11,088.8	$ 11,711.2	$ 7,885.6	$ 5,667.9	$ 5,083.7	$ 3,005.5	$ 717.0	$ 4,636.0	$ 5,829.1	$ 5,357.8	$ 9,857.9	$ 86,559.9
Net Power Supply Expense ($ x 1000)	$ (390.7)	$ 847.3	$ (1,846.9)	$ (220.4)	$ 1,369.4	$ 4,920.5	$ 13,260.1	$ 17,847.0	$ 5,349.5	$ 6,634.3	$ 9,652.8	$ 6,667.0	$ 64,089.8

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,054,558.5	1,123,931.4	934,886.7	1,220,242.6	1,217,508.2	673,892.6	552,614.8	574,600.0	574,659.0	514,199.7	456,444.5	765,838.5	9,663,376.5
Bridger													
Energy (MWh)	470,619.2	423,760.8	470,360.9	357,192.1	320,546.5	366,423.3	470,446.2	469,266.7	448,730.9	468,212.5	455,557.1	470,742.4	5,191,858.6
Cost ($ x 1000)	$ 8,720.1	$ 7,853.8	$ 8,715.7	$ 6,657.2	$ 5,987.6	$ 6,848.4	$ 8,717.1	$ 8,697.0	$ 8,324.5	$ 8,679.1	$ 8,440.8	$ 8,722.2	$ 96,363.6
Boardman													
Energy (MWh)	28,978.5	26,850.9	36,284.3	3,140.2	-	27,074.6	36,100.4	35,623.0	35,043.5	37,525.7	35,576.7	35,005.3	337,203.1
Cost ($ x 1000)	$ 503.1	$ 464.0	$ 607.3	$ 53.5	$ -	$ 470.1	$ 604.7	$ 597.9	$ 586.7	$ 625.0	$ 594.3	$ 589.1	$ 5,695.8
Valmy													
Energy (MWh)	177,859.8	146,806.6	145,794.2	44,046.0	51,954.7	83,369.0	151,434.4	158,357.6	133,294.0	157,412.2	174,489.0	180,007.3	1,604,825.0
Cost ($ x 1000)	$ 4,535.3	$ 3,761.4	$ 3,765.7	$ 1,157.0	$ 1,349.0	$ 2,168.2	$ 3,896.7	$ 4,070.0	$ 3,443.9	$ 4,047.5	$ 4,445.5	$ 4,586.6	$ 41,226.6
Danskin													
Energy (MWh)	-	-	-	-	-	-	21,264.8	11,230.7	523.0	170.0	871.6	4.7	34,064.8
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 767.7	$ 415.9	$ 19.8	$ 6.8	$ 42.3	$ 0.3	$ 1,252.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 1,083.0	$ 731.2	$ 325.8	$ 322.0	$ 348.2	$ 315.5	$ 4,970.6
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	5,876.4	6,614.3	53.1	164.2	34.0	-	12,741.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 213.7	$ 246.1	$ 2.0	$ 6.6	$ 1.7	$ -	$ 470.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 213.7	$ 246.1	$ 2.0	$ 6.6	$ 1.7	$ -	$ 470.1
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	-	-	-	-	344.0	157,622.6	319,677.1	228,248.3	72,315.3	15,554.8	83,384.8	29,406.6	906,553.5
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	31,150.6	221,541.8	387,313.4	289,525.8	94,325.2	46,739.0	113,127.8	66,323.9	1,356,096.7
Market Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ 6.8	$ 3,999.2	$ 13,498.5	$ 7,966.9	$ 2,468.2	$ 581.5	$ 3,601.1	$ 1,438.0	$ 33,560.2
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,181.9	$ 7,067.6	$ 17,085.3	$ 11,192.2	$ 3,617.9	$ 2,200.0	$ 5,454.5	$ 3,731.6	$ 56,297.0
Surplus Sales													
Energy (MWh)	385,918.1	589,281.4	482,970.2	601,976.9	406,462.8	19,721.7	424.6	9,389.5	80,729.9	110,708.1	75,605.8	116,629.9	2,879,819.0
Revenue Including Transmission Costs ($ x 1000)	$ 14,652.9	$ 16,184.5	$ 13,329.8	$ 13,199.8	$ 8,882.1	$ 458.5	$ 10.1	$ 246.1	$ 2,014.9	$ 2,957.7	$ 2,121.5	$ 3,734.3	$ 77,792.2
Transmission Costs ($ x 1000)	$ 385.9	$ 589.3	$ 483.0	$ 602.0	$ 406.5	$ 19.7	$ 0.4	$ 9.4	$ 80.7	$ 110.7	$ 75.6	$ 116.6	$ 2,879.8
Revenue Excluding Transmission Costs ($ x 1000)	$ 14,267.0	$ 15,595.2	$ 12,846.8	$ 12,597.8	$ 8,475.6	$ 438.8	$ 9.7	$ 236.7	$ 1,934.2	$ 2,847.0	$ 2,045.9	$ 3,617.7	$ 74,912.4
Net Power Supply Expense ($ x 1000)	$ 1,355.6	$ (2,028.0)	$ 1,539.1	$ (3,389.6)	$ 358.1	$ 16,421.4	$ 31,590.7	$ 25,297.7	$ 14,366.6	$ 13,033.2	$ 17,239.1	$ 14,327.3	$ 130,111.3

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	962,005.1	1,077,271.0	1,199,010.7	1,174,243.0	1,202,494.9	1,242,255.6	677,888.7	629,591.4	795,135.2	718,945.1	608,080.1	850,898.6	11,137,819.3
Bridger													
Energy (MWh)	470,300.3	393,037.4	418,529.6	337,292.7	304,991.0	317,141.6	459,247.6	454,162.5	413,597.9	444,190.0	455,497.9	470,742.4	4,938,730.9
Cost ($ x 1000)	$ 8,714.7	$ 7,307.6	$ 7,793.8	$ 6,318.1	$ 5,722.5	$ 5,985.9	$ 8,526.3	$ 8,428.3	$ 7,725.7	$ 8,269.7	$ 8,439.8	$ 8,722.2	$ 91,954.6
Boardman													
Energy (MWh)	25,879.9	18,811.8	26,479.4	2,762.2	-	11,537.7	35,738.3	35,434.1	33,903.7	35,042.0	35,132.8	35,899.6	296,621.5
Cost ($ x 1000)	$ 458.8	$ 349.3	$ 467.4	$ 48.1	$ -	$ 212.2	$ 599.5	$ 595.2	$ 570.5	$ 589.6	$ 588.0	$ 601.8	$ 5,080.4
Valmy													
Energy (MWh)	171,407.8	103,988.2	-	-	-	-	131,909.8	125,880.5	57,036.8	113,830.3	157,868.8	180,167.9	1,042,090.1
Cost ($ x 1000)	$ 4,381.2	$ 2,711.1	$ -	$ -	$ -	$ -	$ 3,416.6	$ 3,262.4	$ 1,487.5	$ 2,949.1	$ 4,046.1	$ 4,590.4	$ 26,844.5
Danskin													
Energy (MWh)	-	-	-	-	-	-	11,141.8	12,563.9	390.5	12.1	345.2	-	24,453.5
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 358.6	$ 415.6	$ 13.2	$ 0.4	$ 14.9	$ -	$ 802.7
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 673.8	$ 730.9	$ 319.1	$ 315.7	$ 320.8	$ 315.3	$ 4,520.6
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	1,854.1	7,923.8	204.9	-	89.7	-	10,072.5
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 60.1	$ 262.8	$ 7.0	$ -	$ 3.9	$ -	$ 333.7
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 60.1	$ 262.8	$ 7.0	$ -	$ 3.9	$ -	$ 333.7
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	-	314.7	-	-	822.1	5,902.4	240,468.0	221,734.6	28,001.8	204.0	14,385.8	7,747.6	519,581.1
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	30,054.1	23,507.9	25,715.8	27,086.1	31,628.7	69,821.5	308,104.4	283,012.1	50,011.8	31,388.2	44,128.8	44,665.0	969,124.3
Market Cost ($ x 1000)	$ -	$ 7.2	$ -	$ -	$ 21.0	$ 138.2	$ 7,337.5	$ 7,085.2	$ 825.7	$ 5.2	$ 577.0	$ 345.7	$ 16,342.6
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 1,548.9	$ 1,207.9	$ 981.9	$ 1,034.6	$ 1,196.1	$ 3,206.5	$ 10,924.4	$ 10,310.5	$ 1,975.3	$ 1,623.6	$ 2,430.5	$ 2,639.3	$ 39,079.5
Surplus Sales													
Energy (MWh)	283,495.0	461,354.8	539,663.9	491,653.9	324,417.4	288,176.9	1,259.0	12,739.7	144,382.0	229,692.5	140,648.3	181,081.2	3,098,564.6
Revenue Including Transmission Costs ($ x 1000)	$ 9,522.8	$ 10,306.3	$ 11,686.6	$ 9,774.5	$ 6,081.3	$ 4,888.8	$ 30.1	$ 333.5	$ 3,321.5	$ 5,827.0	$ 3,928.1	$ 5,758.1	$ 71,458.4
Transmission Costs ($ x 1000)	$ 283.5	$ 461.4	$ 539.7	$ 491.7	$ 324.4	$ 288.2	$ 1.3	$ 12.7	$ 144.4	$ 229.7	$ 140.6	$ 181.1	$ 3,098.6
Revenue Excluding Transmission Costs ($ x 1000)	$ 9,239.3	$ 9,844.9	$ 11,146.9	$ 9,282.8	$ 5,756.9	$ 4,600.6	$ 28.8	$ 320.7	$ 3,177.1	$ 5,597.3	$ 3,787.5	$ 5,577.0	$ 68,359.9
Net Power Supply Expense ($ x 1000)	$ 6,179.5	$ 2,018.3	$ (1,588.5)	$ (1,576.1)	$ 1,477.0	$ 5,110.0	$ 24,171.9	$ 23,269.3	$ 8,908.0	$ 8,150.4	$ 12,041.7	$ 11,292.0	$ 99,453.4

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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	858,120.6	738,722.4	825,000.6	840,574.4	725,053.0	575,518.7	531,630.1	534,267.0	391,784.1	444,280.5	418,048.5	493,378.5	7,376,378.4
Bridger													
Energy (MWh)	470,742.4	425,186.7	470,709.2	383,427.2	350,652.6	382,709.8	470,742.4	470,683.8	454,908.5	470,691.1	455,557.1	470,742.4	5,276,753.2
Cost ($ x 1000)	$ 8,722.2	$ 7,878.1	$ 8,721.6	$ 7,104.4	$ 6,500.7	$ 7,126.0	$ 8,722.2	$ 8,721.2	$ 8,429.8	$ 8,721.3	$ 8,440.8	$ 8,722.2	$ 97,810.5
Boardman													
Energy (MWh)	34,760.4	33,238.5	37,597.8	3,473.4	-	27,160.8	38,134.7	38,151.3	35,550.8	35,999.4	35,078.1	33,270.4	352,415.8
Cost ($ x 1000)	$ 585.6	$ 555.2	$ 626.1	$ 58.2	$ -	$ 468.5	$ 633.7	$ 634.0	$ 594.0	$ 603.3	$ 587.2	$ 564.3	$ 5,910.0
Valmy													
Energy (MWh)	180,320.6	162,677.4	178,140.3	142,418.6	143,648.8	158,403.0	180,269.8	180,340.3	174,283.7	179,877.1	174,531.2	180,054.6	2,034,965.3
Cost ($ x 1000)	$ 4,594.0	$ 4,144.9	$ 4,542.0	$ 3,643.3	$ 3,680.7	$ 4,061.6	$ 4,592.8	$ 4,594.5	$ 4,440.6	$ 4,583.4	$ 4,446.5	$ 4,587.7	$ 51,912.0
Danskin													
Energy (MWh)	-	-	-	-	-	48.0	35,463.9	21,844.2	1,500.8	238.6	13.8	-	59,109.4
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 2.2	$ 1,607.4	$ 1,016.2	$ 71.4	$ 12.0	$ 0.8	$ -	$ 2,710.0
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 308.1	$ 1,922.7	$ 1,331.4	$ 377.4	$ 327.2	$ 306.8	$ 315.3	$ 6,427.9
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	10,508.9	11,646.6	4.8	-	-	-	22,160.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 479.8	$ 544.4	$ 0.2	$ -	$ -	$ -	$ 1,024.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 479.8	$ 544.4	$ 0.2	$ -	$ -	$ -	$ 1,024.4
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	-	-	-	-	81,033.9	153,488.4	292,440.7	227,554.9	183,745.1	46,700.7	103,913.5	196,497.4	1,285,374.6
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	111,840.5	217,407.6	360,077.0	288,832.3	205,755.1	77,884.9	133,656.6	233,414.7	1,734,917.8
Market Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ 2,862.2	$ 5,063.5	$ 19,292.7	$ 11,446.3	$ 7,857.6	$ 2,028.4	$ 5,371.8	$ 10,366.8	$ 64,289.4
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 4,037.4	$ 8,131.9	$ 22,879.5	$ 14,671.6	$ 9,007.2	$ 3,646.9	$ 7,225.3	$ 12,660.4	$ 87,026.2
Surplus Sales													
Energy (MWh)	197,846.1	227,756.7	407,092.1	347,249.7	116,497.7	8,668.3	2,201.1	9,936.9	57,889.0	95,256.4	56,390.2	9,568.4	1,536,352.7
Revenue Including Transmission Costs ($ x 1000)	$ 10,928.2	$ 9,457.7	$ 14,301.9	$ 9,988.1	$ 2,694.8	$ 199.9	$ 60.6	$ 267.5	$ 1,515.1	$ 2,644.0	$ 1,803.4	$ 285.6	$ 54,146.8
Transmission Costs ($ x 1000)	$ 197.8	$ 227.8	$ 407.1	$ 347.2	$ 116.5	$ 8.7	$ 2.2	$ 9.9	$ 57.9	$ 95.3	$ 56.4	$ 9.6	$ 1,536.4
Revenue Excluding Transmission Costs ($ x 1000)	$ 10,730.4	$ 9,230.0	$ 13,894.8	$ 9,640.9	$ 2,578.3	$ 191.2	$ 58.4	$ 257.5	$ 1,457.2	$ 2,548.7	$ 1,747.0	$ 276.0	$ 52,610.5
Net Power Supply Expense ($ x 1000)	$ 5,035.6	$ 4,836.2	$ 1,292.1	$ 2,505.6	$ 11,955.7	$ 19,904.8	$ 39,172.3	$ 30,239.5	$ 21,391.9	$ 15,333.4	$ 19,259.6	$ 26,573.8	$ 197,500.5

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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	480,189.5	583,781.3	668,185.2	584,066.0	671,933.7	593,101.5	475,981.2	488,740.4	349,490.2	405,294.0	410,451.4	481,867.5	6,193,081.8
Bridger													
Energy (MWh)	470,742.4	425,186.7	470,742.4	383,427.2	351,825.3	392,235.8	470,742.4	470,742.4	455,557.1	470,742.4	455,557.1	470,742.4	5,288,243.5
Cost ($ x 1000)	$ 8,722.2	$ 7,878.1	$ 8,722.2	$ 7,104.4	$ 6,520.7	$ 7,288.3	$ 8,722.2	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 98,006.3
Boardman													
Energy (MWh)	32,671.2	33,452.2	37,419.2	3,574.6	-	28,957.0	38,707.6	38,401.3	36,736.8	37,802.1	35,018.7	34,226.3	356,966.9
Cost ($ x 1000)	$ 555.8	$ 558.2	$ 623.5	$ 59.7	$ -	$ 497.0	$ 641.9	$ 637.5	$ 610.9	$ 629.0	$ 586.4	$ 578.0	$ 5,977.8
Valmy													
Energy (MWh)	180,214.6	162,895.8	179,735.5	149,943.9	146,137.9	162,220.3	180,348.9	180,348.9	174,498.8	179,882.3	174,403.8	180,270.8	2,050,901.6
Cost ($ x 1000)	$ 4,591.5	$ 4,150.1	$ 4,580.1	$ 3,823.0	$ 3,740.0	$ 4,152.6	$ 4,594.7	$ 4,594.7	$ 4,445.7	$ 4,583.6	$ 4,443.5	$ 4,592.8	$ 52,292.3
Danskin													
Energy (MWh)	-	-	-	-	-	29.6	41,039.1	25,126.6	6,171.6	1,762.8	-	-	74,129.8
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 1.5	$ 2,054.4	$ 1,289.9	$ 324.5	$ 97.8	$ -	$ -	$ 3,768.0
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 307.4	$ 2,369.6	$ 1,605.1	$ 630.5	$ 413.0	$ 305.9	$ 315.3	$ 7,485.8
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	13,839.3	13,200.8	488.6	107.3	-	-	27,636.0
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 697.9	$ 681.6	$ 25.9	$ 6.0	$ -	$ -	$ 1,411.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 697.9	$ 681.6	$ 25.9	$ 6.0	$ -	$ -	$ 1,411.3
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	183,182.9	4,121.7	-	9,802.1	109,850.2	131,867.5	336,959.2	263,386.0	210,155.9	66,596.5	109,349.1	206,153.5	1,631,424.7
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	213,236.9	27,314.8	25,715.8	36,888.3	140,656.8	195,786.7	404,595.6	324,663.4	232,165.9	97,780.7	139,092.1	243,070.8	2,080,967.9
Market Cost ($ x 1000)	$ 11,176.2	$ 200.2	$ -	$ 405.5	$ 4,287.2	$ 5,014.7	$ 24,850.6	$ 14,341.1	$ 10,441.4	$ 3,470.2	$ 6,124.9	$ 12,103.9	$ 92,416.0
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 12,725.1	$ 1,400.9	$ 981.9	$ 1,440.1	$ 5,462.3	$ 8,083.1	$ 28,437.4	$ 17,566.4	$ 11,591.1	$ 5,088.7	$ 7,978.3	$ 14,397.5	$ 115,152.8
Surplus Sales													
Energy (MWh)	902.5	77,369.3	251,726.5	108,169.9	95,856.6	19,751.4	628.4	5,395.3	49,210.3	79,656.3	54,028.2	8,885.5	751,580.1
Revenue Including Transmission Costs ($ x 1000)	$ 49.2	$ 3,525.0	$ 9,639.3	$ 3,587.9	$ 2,143.0	$ 463.8	$ 18.7	$ 161.6	$ 1,434.9	$ 2,534.9	$ 1,851.9	$ 309.0	$ 25,719.3
Transmission Costs ($ x 1000)	$ 0.9	$ 77.4	$ 251.7	$ 108.2	$ 95.9	$ 19.8	$ 0.6	$ 5.4	$ 49.2	$ 79.7	$ 54.0	$ 8.9	$ 751.6
Revenue Excluding Transmission Costs ($ x 1000)	$ 48.3	$ 3,447.6	$ 9,387.6	$ 3,479.7	$ 2,047.2	$ 444.0	$ 18.1	$ 156.2	$ 1,385.7	$ 2,455.3	$ 1,797.8	$ 300.1	$ 24,967.7
Net Power Supply Expense ($ x 1000)	$ 26,861.5	$ 10,827.0	$ 5,835.4	$ 9,253.3	$ 13,991.1	$ 19,884.4	$ 45,445.6	$ 33,651.3	$ 24,359.2	$ 16,987.2	$ 19,957.1	$ 28,305.7	$ 255,358.7

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
Hoku Annualized
1989

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	456,958.1	633,674.5	924,296.9	887,897.6	1,049,968.2	660,518.0	526,834.5	541,523.2	427,992.5	502,728.7	470,094.9	674,303.7	7,756,790.8
Bridger													
Energy (MWh)	470,742.4	425,186.7	470,739.0	382,872.3	343,753.4	377,117.4	470,715.5	470,742.4	455,272.9	470,742.4	455,557.1	470,742.4	5,264,183.7
Cost ($ x 1000)	$ 8,722.2	$ 7,878.1	$ 8,722.1	$ 7,094.9	$ 6,383.1	$ 7,030.7	$ 8,721.7	$ 8,722.2	$ 8,436.0	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 97,596.2
Boardman													
Energy (MWh)	36,393.5	32,996.1	35,040.6	3,361.0	-	28,091.0	38,450.2	37,771.4	36,229.1	37,647.7	37,150.3	38,010.1	361,140.9
Cost ($ x 1000)	$ 608.9	$ 551.7	$ 589.6	$ 56.6	$ -	$ 484.6	$ 638.2	$ 628.5	$ 603.6	$ 626.8	$ 616.8	$ 632.0	$ 6,037.4
Valmy													
Energy (MWh)	180,347.6	162,799.9	174,140.2	139,007.6	133,123.9	156,921.3	180,320.5	180,348.9	174,309.1	180,332.4	174,457.3	180,348.9	2,016,457.8
Cost ($ x 1000)	$ 4,594.7	$ 4,147.8	$ 4,446.5	$ 3,561.9	$ 3,429.7	$ 4,026.2	$ 4,594.0	$ 4,594.7	$ 4,441.2	$ 4,594.3	$ 4,444.7	$ 4,594.7	$ 51,470.6
Danskin													
Energy (MWh)	-	-	-	-	-	-	36,588.4	19,138.0	1,970.1	878.8	1,152.7	-	59,728.0
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,667.3	$ 894.2	$ 94.3	$ 44.3	$ 70.9	$ -	$ 2,771.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 1,982.6	$ 1,209.4	$ 400.2	$ 359.6	$ 376.9	$ 315.3	$ 6,488.9
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	12,032.6	9,150.4	95.1	83.5	15.1	-	21,376.8
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 552.3	$ 430.0	$ 4.6	$ 4.2	$ 0.9	$ -	$ 992.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 552.3	$ 430.0	$ 4.6	$ 4.2	$ 0.9	$ -	$ 992.1
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	202,888.0	3,846.8	-	-	1,035.1	103,075.3	294,139.2	227,272.3	156,243.3	18,854.5	73,080.8	72,798.2	1,153,233.6
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	232,942.1	27,039.9	25,715.8	27,086.1	31,841.7	166,994.5	361,775.6	288,549.7	178,253.3	50,038.7	102,823.8	109,715.5	1,602,776.8
Market Cost ($ x 1000)	$ 12,363.4	$ 167.9	$ -	$ -	$ 33.5	$ 3,447.7	$ 20,591.8	$ 10,794.3	$ 6,933.7	$ 894.9	$ 4,128.3	$ 4,517.0	$ 63,872.4
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 13,912.3	$ 1,368.5	$ 981.9	$ 1,034.6	$ 1,208.7	$ 6,516.1	$ 24,178.7	$ 14,019.6	$ 8,083.3	$ 2,513.4	$ 5,981.7	$ 6,810.6	$ 86,609.3
Surplus Sales													
Energy (MWh)	1,231.6	126,435.5	499,860.9	390,494.5	343,990.1	37,062.6	2,091.6	11,395.4	68,223.3	128,737.0	80,756.2	71,828.4	1,762,107.3
Revenue Including Transmission Costs ($ x 1000)	$ 73.3	$ 5,174.7	$ 16,222.0	$ 10,691.4	$ 8,769.5	$ 952.2	$ 57.8	$ 312.8	$ 1,866.0	$ 4,077.7	$ 2,940.7	$ 3,049.2	$ 54,187.2
Transmission Costs ($ x 1000)	$ 1.2	$ 126.4	$ 499.9	$ 390.5	$ 344.0	$ 37.1	$ 2.1	$ 11.4	$ 68.2	$ 128.7	$ 80.8	$ 71.8	$ 1,762.1
Revenue Excluding Transmission Costs ($ x 1000)	$ 72.0	$ 5,048.2	$ 15,722.2	$ 10,300.9	$ 8,425.5	$ 915.1	$ 55.7	$ 301.4	$ 1,797.7	$ 3,949.0	$ 2,860.0	$ 2,977.4	$ 52,425.1
Net Power Supply Expense ($ x 1000)	$ 28,081.3	$ 9,185.3	$ (666.7)	$ 1,753.1	$ 2,911.2	$ 17,448.4	$ 40,611.9	$ 29,303.1	$ 20,171.2	$ 12,871.5	$ 17,001.9	$ 18,097.3	$ 196,769.5

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
Hoku Annualized
1990

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	603,173.7	724,839.8	682,183.0	623,861.9	682,670.2	729,756.4	499,044.6	509,426.9	364,722.9	446,590.4	417,207.8	479,186.1	6,762,663.7
Bridger													
Energy (MWh)	470,742.4	424,755.7	470,432.6	381,869.7	342,193.8	375,947.7	470,742.4	470,742.4	455,557.1	470,683.5	455,557.1	470,742.4	5,259,966.6
Cost ($ x 1000)	$ 8,722.2	$ 7,870.8	$ 8,716.9	$ 7,077.8	$ 6,356.5	$ 7,010.7	$ 8,722.2	$ 8,722.2	$ 8,440.8	$ 8,721.2	$ 8,440.8	$ 8,722.2	$ 97,524.4
Boardman													
Energy (MWh)	32,000.9	25,348.9	31,714.2	3,267.2	-	28,139.6	38,195.4	37,839.9	35,789.5	37,371.3	34,530.0	35,381.6	339,578.5
Cost ($ x 1000)	$ 546.2	$ 442.6	$ 542.1	$ 55.3	$ -	$ 485.3	$ 634.6	$ 629.5	$ 597.4	$ 622.8	$ 579.4	$ 594.4	$ 5,729.7
Valmy													
Energy (MWh)	179,864.1	156,196.3	170,440.9	140,878.7	125,694.3	148,462.6	180,317.5	180,324.1	174,378.9	180,199.0	174,499.9	180,305.6	1,991,561.9
Cost ($ x 1000)	$ 4,583.1	$ 3,990.1	$ 4,358.2	$ 3,606.6	$ 3,238.4	$ 3,812.7	$ 4,594.0	$ 4,594.1	$ 4,442.9	$ 4,591.1	$ 4,445.7	$ 4,593.7	$ 50,850.7
Danskin													
Energy (MWh)	-	-	-	-	-	-	36,854.9	21,771.5	2,462.4	712.5	-	-	61,801.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,625.4	$ 984.4	$ 114.0	$ 34.8	$ -	$ -	$ 2,758.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 1,940.6	$ 1,299.6	$ 420.0	$ 350.0	$ 305.9	$ 315.3	$ 6,476.4
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	12,396.4	10,616.2	134.5	53.0	-	-	23,200.2
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 550.7	$ 482.8	$ 6.3	$ 2.6	$ -	$ -	$ 1,042.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 550.7	$ 482.8	$ 6.3	$ 2.6	$ -	$ -	$ 1,042.3
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	72,986.5	-	-	4,242.1	106,046.8	61,462.2	320,517.6	251,001.2	203,619.5	44,901.3	103,904.6	206,780.7	1,375,462.7
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	103,040.6	23,193.1	25,715.8	31,328.2	136,853.4	125,381.4	388,153.9	312,278.7	225,629.4	76,085.6	133,647.7	243,698.0	1,825,005.8
Market Cost ($ x 1000)	$ 3,866.7	$ -	$ -	$ 148.6	$ 3,191.6	$ 2,019.2	$ 22,807.5	$ 11,780.9	$ 8,644.1	$ 2,015.2	$ 5,170.6	$ 11,208.2	$ 70,852.7
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 5,415.5	$ 1,200.7	$ 981.9	$ 1,183.2	$ 4,366.7	$ 5,087.6	$ 26,394.3	$ 15,006.2	$ 9,793.8	$ 3,633.7	$ 7,024.1	$ 13,501.8	$ 93,589.5
Surplus Sales													
Energy (MWh)	12,669.6	199,072.4	250,414.9	131,475.6	72,714.5	55,108.0	1,079.3	7,171.2	52,776.1	97,980.1	54,947.5	8,021.5	943,430.7
Revenue Including Transmission Costs ($ x 1000)	$ 577.9	$ 6,784.7	$ 7,740.5	$ 3,719.1	$ 1,405.8	$ 1,403.9	$ 28.8	$ 190.9	$ 1,375.7	$ 2,790.1	$ 1,667.5	$ 258.3	$ 27,943.3
Transmission Costs ($ x 1000)	$ 12.7	$ 199.1	$ 250.4	$ 131.5	$ 72.7	$ 55.1	$ 1.1	$ 7.2	$ 52.8	$ 98.0	$ 54.9	$ 8.0	$ 943.4
Revenue Excluding Transmission Costs ($ x 1000)	$ 565.2	$ 6,585.6	$ 7,490.1	$ 3,587.6	$ 1,333.1	$ 1,348.8	$ 27.7	$ 183.7	$ 1,322.9	$ 2,692.1	$ 1,612.6	$ 250.3	$ 26,999.8
Net Power Supply Expense ($ x 1000)	$ 19,017.1	$ 7,205.8	$ 7,424.3	$ 8,641.2	$ 12,943.7	$ 15,353.5	$ 42,808.7	$ 30,550.8	$ 22,378.1	$ 15,229.4	$ 19,183.4	$ 27,477.0	$ 228,213.1

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
Hoku Annualized
1991

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	469,951.5	694,566.5	642,412.7	491,563.7	776,257.5	659,159.0	515,294.7	516,135.9	385,621.4	421,612.6	414,421.5	485,168.6	6,472,165.8
Bridger													
Energy (MWh)	470,742.4	423,405.4	466,457.7	379,829.6	343,209.9	392,611.8	470,742.4	470,742.4	455,557.1	470,742.4	455,557.1	470,742.4	5,270,340.4
Cost ($ x 1000)	$ 8,722.2	$ 7,847.8	$ 8,649.2	$ 7,043.1	$ 6,373.8	$ 7,294.7	$ 8,722.2	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 97,701.2
Boardman													
Energy (MWh)	23,700.2	23,506.1	29,019.8	2,712.7	-	30,185.7	37,462.1	37,673.5	36,144.3	37,884.6	36,146.2	37,167.6	331,602.7
Cost ($ x 1000)	$ 422.0	$ 416.3	$ 503.6	$ 47.4	$ -	$ 514.5	$ 624.1	$ 627.1	$ 602.4	$ 630.2	$ 602.5	$ 619.9	$ 5,610.1
Valmy													
Energy (MWh)	175,118.4	147,148.7	165,343.7	126,573.9	134,758.7	160,192.3	180,106.9	180,348.9	174,531.2	180,111.8	174,474.7	180,091.9	1,978,801.3
Cost ($ x 1000)	$ 4,469.8	$ 3,771.9	$ 4,236.6	$ 3,255.9	$ 3,468.6	$ 4,104.3	$ 4,588.9	$ 4,594.7	$ 4,446.5	$ 4,589.1	$ 4,445.1	$ 4,588.6	$ 50,560.1
Danskin													
Energy (MWh)	-	-	-	-	-	-	28,793.4	20,075.3	4,087.3	1,448.4	545.6	466.5	55,416.4
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,352.0	$ 966.1	$ 201.6	$ 75.3	$ 34.6	$ 35.6	$ 2,665.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 1,667.3	$ 1,281.4	$ 507.5	$ 390.6	$ 340.6	$ 350.8	$ 6,383.1
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	5,417.6	8,600.3	458.1	112.0	3.9	-	14,591.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 256.3	$ 416.5	$ 22.8	$ 5.9	$ 0.2	$ -	$ 701.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 256.3	$ 416.5	$ 22.8	$ 5.9	$ 0.2	$ -	$ 701.6
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	207,940.8	438.9	100.6	63,565.6	53,716.2	88,069.8	320,552.6	249,137.5	185,846.2	57,480.2	105,659.5	200,986.1	1,533,494.1
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	237,994.9	23,632.0	25,816.5	90,651.7	84,522.8	151,988.9	388,189.0	310,414.9	207,856.2	88,664.4	135,402.5	237,903.4	1,983,037.3
Market Cost ($ x 1000)	$ 9,758.1	$ 9.1	$ 2.1	$ 1,905.9	$ 1,804.0	$ 3,205.5	$ 17,750.8	$ 12,003.0	$ 8,596.3	$ 2,805.8	$ 5,805.3	$ 12,137.3	$ 75,783.3
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 11,307.0	$ 1,209.7	$ 984.1	$ 2,940.5	$ 2,979.1	$ 6,273.9	$ 21,337.7	$ 15,228.3	$ 9,746.0	$ 4,424.3	$ 7,658.7	$ 14,430.9	$ 98,520.1
Surplus Sales													
Energy (MWh)	1,355.3	156,997.2	198,978.7	41,601.5	124,051.9	41,558.2	1,380.4	8,162.6	58,356.9	86,861.0	56,056.5	10,248.2	785,608.4
Revenue Including Transmission Costs ($ x 1000)	$ 62.8	$ 5,147.5	$ 5,964.6	$ 1,017.9	$ 2,644.0	$ 1,025.6	$ 37.6	$ 226.0	$ 1,603.6	$ 2,625.0	$ 1,954.9	$ 398.7	$ 22,708.1
Transmission Costs ($ x 1000)	$ 1.4	$ 157.0	$ 199.0	$ 41.6	$ 124.1	$ 41.6	$ 1.4	$ 8.2	$ 58.4	$ 86.9	$ 56.1	$ 10.2	$ 785.6
Revenue Excluding Transmission Costs ($ x 1000)	$ 61.4	$ 4,990.5	$ 5,765.6	$ 976.3	$ 2,519.9	$ 984.0	$ 36.2	$ 217.9	$ 1,545.2	$ 2,538.2	$ 1,898.8	$ 388.5	$ 21,922.5
Net Power Supply Expense ($ x 1000)	$ 25,174.8	$ 8,542.5	$ 8,923.2	$ 12,616.4	$ 10,616.9	$ 17,509.4	$ 37,160.3	$ 30,652.4	$ 22,220.8	$ 16,224.0	$ 19,589.2	$ 28,323.9	$ 237,553.7

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
Hoku Annualized
1992

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	451,811.0	540,270.9	618,076.9	481,644.1	488,780.2	384,418.9	452,153.2	444,900.1	331,126.6	334,972.7	401,994.8	443,229.7	5,373,379.1
Bridger													
Energy (MWh)	470,742.4	425,186.7	470,742.4	383,427.2	352,329.6	393,050.4	470,742.4	470,742.4	455,381.2	470,742.4	455,557.1	470,742.4	5,289,386.5
Cost ($ x 1000)	$ 8,722.2	$ 7,878.1	$ 8,722.2	$ 7,104.4	$ 6,529.3	$ 7,302.2	$ 8,722.2	$ 8,722.2	$ 8,437.8	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 98,025.8
Boardman													
Energy (MWh)	35,246.4	33,506.4	38,013.7	3,418.5	-	28,033.0	38,705.3	38,323.5	36,115.8	36,750.4	35,665.9	34,376.1	358,154.9
Cost ($ x 1000)	$ 592.5	$ 559.0	$ 632.0	$ 57.4	$ -	$ 480.9	$ 641.9	$ 636.4	$ 602.0	$ 614.0	$ 595.6	$ 580.1	$ 5,991.9
Valmy													
Energy (MWh)	180,348.9	162,698.5	179,620.5	143,034.0	147,443.5	164,208.5	180,348.9	180,348.9	174,531.2	180,175.3	174,379.2	180,135.4	2,047,272.9
Cost ($ x 1000)	$ 4,594.7	$ 4,145.4	$ 4,577.3	$ 3,658.0	$ 3,771.1	$ 4,200.1	$ 4,594.7	$ 4,594.7	$ 4,446.5	$ 4,590.6	$ 4,442.9	$ 4,589.6	$ 52,205.6
Danskin													
Energy (MWh)	-	-	-	-	-	806.3	43,006.8	29,450.3	3,634.1	408.8	202.5	-	77,508.7
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 39.9	$ 2,149.4	$ 1,509.8	$ 190.8	$ 22.6	$ 13.7	$ -	$ 3,926.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 345.8	$ 2,464.6	$ 1,825.0	$ 496.7	$ 337.9	$ 319.6	$ 315.3	$ 7,644.0
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	0.2	14,690.7	16,448.1	369.3	21.7	9.6	-	31,539.5
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 0.0	$ 739.6	$ 847.8	$ 19.5	$ 1.2	$ 0.7	$ -	$ 1,608.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ 0.0	$ 739.6	$ 847.8	$ 19.5	$ 1.2	$ 0.7	$ -	$ 1,608.8
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	208,560.9	15,803.3	45.5	55,015.0	237,738.5	318,394.0	357,602.1	297,984.9	225,668.3	115,991.2	116,574.2	240,007.5	2,189,385.5
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	238,615.0	38,996.4	25,761.3	82,101.1	268,545.1	382,313.2	425,238.5	359,262.3	247,678.3	147,175.4	146,317.2	276,924.8	2,638,928.7
Market Cost ($ x 1000)	$ 13,604.4	$ 759.7	$ 2.2	$ 2,053.3	$ 9,249.6	$ 11,505.8	$ 28,561.4	$ 16,821.2	$ 10,861.5	$ 5,567.5	$ 6,737.2	$ 14,003.8	$ 119,727.7
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 15,153.3	$ 1,960.3	$ 984.2	$ 3,087.9	$ 10,424.8	$ 14,574.1	$ 32,148.3	$ 20,046.5	$ 12,011.2	$ 7,185.9	$ 8,590.7	$ 16,297.4	$ 142,464.6
Surplus Sales													
Energy (MWh)	611.7	45,397.4	202,143.2	43,894.8	42,401.3	250.9	260.1	3,647.1	42,937.8	56,531.4	53,631.3	4,116.2	495,823.0
Revenue Including Transmission Costs ($ x 1000)	$ 27.0	$ 2,031.8	$ 7,689.4	$ 1,247.5	$ 925.1	$ 5.7	$ 7.4	$ 106.8	$ 1,210.0	$ 1,631.1	$ 1,906.6	$ 140.3	$ 16,928.6
Transmission Costs ($ x 1000)	$ 0.6	$ 45.4	$ 202.1	$ 43.9	$ 42.4	$ 0.3	$ 0.3	$ 3.6	$ 42.9	$ 56.5	$ 53.6	$ 4.1	$ 495.8
Revenue Excluding Transmission Costs ($ x 1000)	$ 26.4	$ 1,986.4	$ 7,487.2	$ 1,203.6	$ 882.7	$ 5.5	$ 7.2	$ 103.1	$ 1,167.0	$ 1,574.5	$ 1,853.0	$ 136.2	$ 16,432.8
Net Power Supply Expense ($ x 1000)	$ 29,351.6	$ 12,843.8	$ 7,743.7	$ 13,010.1	$ 20,157.7	$ 26,897.6	$ 49,304.1	$ 36,569.6	$ 24,846.8	$ 19,877.2	$ 20,537.3	$ 30,368.3	$ 291,507.9

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
Hoku Annualized
1993

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	443,751.2	635,742.4	988,421.2	993,827.2	1,101,590.8	1,238,371.6	646,363.5	645,451.2	488,946.7	528,516.4	412,385.4	692,288.6	8,815,656.3
Bridger													
Energy (MWh)	470,742.4	425,186.7	470,712.4	383,127.6	336,912.1	372,468.5	470,409.9	470,700.9	455,260.7	470,742.4	455,557.1	470,742.4	5,252,563.0
Cost ($ x 1000)	$ 8,722.2	$ 7,878.1	$ 8,721.7	$ 7,099.3	$ 6,266.5	$ 6,951.4	$ 8,716.5	$ 8,721.5	$ 8,435.8	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 97,398.2
Boardman													
Energy (MWh)	36,405.3	32,281.9	36,939.3	3,540.2	-	26,497.0	36,685.1	37,522.3	35,592.4	36,875.0	36,265.6	36,646.0	355,250.1
Cost ($ x 1000)	$ 609.0	$ 541.5	$ 616.7	$ 59.2	$ -	$ 459.0	$ 613.0	$ 625.0	$ 594.6	$ 615.8	$ 604.2	$ 612.5	$ 5,950.4
Valmy													
Energy (MWh)	180,348.9	162,150.2	171,930.6	144,172.2	124,069.8	133,784.3	179,811.8	180,348.9	174,398.5	180,085.3	174,517.9	180,348.9	1,985,967.5
Cost ($ x 1000)	$ 4,594.7	$ 4,132.3	$ 4,393.8	$ 3,685.2	$ 3,206.8	$ 3,460.3	$ 4,581.9	$ 4,594.7	$ 4,443.3	$ 4,588.4	$ 4,446.2	$ 4,594.7	$ 50,722.3
Danskin													
Energy (MWh)	-	-	-	-	-	-	17,777.2	17,513.8	740.4	622.7	890.4	-	37,544.5
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 750.6	$ 758.9	$ 32.8	$ 29.1	$ 50.7	$ -	$ 1,622.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 1,065.8	$ 1,074.2	$ 338.8	$ 344.4	$ 356.6	$ 315.3	$ 5,340.0
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	2,040.6	8,262.3	6.4	60.4	7.6	-	10,377.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 86.8	$ 359.7	$ 0.3	$ 2.8	$ 0.4	$ -	$ 450.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 86.8	$ 359.7	$ 0.3	$ 2.8	$ 0.4	$ -	$ 450.1
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	215,916.1	4,870.2	-	-	826.1	409.6	217,056.8	148,936.0	116,358.1	12,266.3	108,913.8	66,313.8	891,866.9
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	245,970.2	28,063.3	25,715.8	27,086.1	31,632.7	64,328.8	284,693.2	210,213.5	138,368.1	43,450.5	138,656.8	103,231.1	1,341,410.1
Market Cost ($ x 1000)	$ 12,405.7	$ 184.1	$ -	$ -	$ 25.6	$ 14.0	$ 9,713.8	$ 6,641.6	$ 4,731.0	$ 533.6	$ 5,478.8	$ 3,577.0	$ 43,305.1
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 13,954.6	$ 1,384.7	$ 981.9	$ 1,034.6	$ 1,200.7	$ 3,082.3	$ 13,300.7	$ 9,866.9	$ 5,880.6	$ 2,152.0	$ 7,332.3	$ 5,870.7	$ 66,041.9
Surplus Sales													
Energy (MWh)	1,066.0	128,163.0	563,647.7	502,023.3	379,508.3	482,870.7	13,155.5	34,184.3	87,414.5	146,637.6	57,785.8	81,964.7	2,478,421.4
Revenue Including Transmission Costs ($ x 1000)	$ 58.7	$ 4,827.8	$ 17,384.9	$ 13,676.8	$ 9,265.4	$ 11,944.7	$ 336.5	$ 935.1	$ 2,280.3	$ 4,368.9	$ 1,855.5	$ 3,037.7	$ 69,972.4
Transmission Costs ($ x 1000)	$ 1.1	$ 128.2	$ 563.6	$ 502.0	$ 379.5	$ 482.9	$ 13.2	$ 34.2	$ 87.4	$ 146.6	$ 57.8	$ 82.0	$ 2,478.4
Revenue Excluding Transmission Costs ($ x 1000)	$ 57.7	$ 4,699.6	$ 16,821.2	$ 13,174.8	$ 8,885.9	$ 11,461.8	$ 323.3	$ 900.9	$ 2,192.9	$ 4,222.3	$ 1,797.7	$ 2,955.7	$ 67,494.0
Net Power Supply Expense ($ x 1000)	$ 28,138.2	$ 9,524.3	$ (1,791.9)	$ (990.6)	$ 2,103.3	$ 2,797.2	$ 28,041.4	$ 24,341.0	$ 17,500.4	$ 12,203.3	$ 19,382.9	$ 17,159.6	$ 158,409.0

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
Hoku Annualized
1994

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	677,989.9	637,640.8	666,056.2	578,920.6	733,320.8	570,447.1	538,203.3	534,602.9	355,561.2	443,641.8	411,486.7	497,899.6	6,645,770.9
Bridger													
Energy (MWh)	470,742.4	425,186.7	470,742.4	383,427.2	352,946.4	392,532.1	470,742.4	470,742.4	455,557.1	470,742.4	455,557.1	470,742.4	5,289,660.9
Cost ($ x 1000)	$ 8,722.2	$ 7,878.1	$ 8,722.2	$ 7,104.4	$ 6,539.8	$ 7,293.4	$ 8,722.2	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 98,030.5
Boardman													
Energy (MWh)	38,908.7	34,229.6	38,554.8	3,588.2	-	28,968.4	38,627.3	37,748.5	36,697.0	38,443.0	37,587.6	38,930.5	372,283.5
Cost ($ x 1000)	$ 644.8	$ 569.3	$ 639.7	$ 59.9	$ -	$ 497.1	$ 640.8	$ 628.2	$ 610.3	$ 638.1	$ 623.0	$ 645.1	$ 6,196.4
Valmy													
Energy (MWh)	180,348.9	162,895.8	179,852.3	149,977.9	148,040.2	162,783.7	180,348.9	180,348.9	174,531.2	180,306.5	174,531.2	180,348.9	2,054,314.7
Cost ($ x 1000)	$ 4,594.7	$ 4,150.1	$ 4,582.9	$ 3,823.8	$ 3,785.3	$ 4,166.0	$ 4,594.7	$ 4,594.7	$ 4,446.5	$ 4,593.7	$ 4,446.5	$ 4,594.7	$ 52,373.6
Danskin													
Energy (MWh)	-	-	-	-	-	4.1	36,213.0	17,980.3	4,757.1	2,913.1	1,858.4	809.2	64,535.2
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 0.2	$ 1,862.9	$ 947.9	$ 257.1	$ 166.1	$ 129.4	$ 67.7	$ 3,431.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 306.2	$ 2,178.2	$ 1,263.1	$ 563.0	$ 481.3	$ 435.3	$ 383.0	$ 7,149.2
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	9,718.9	6,407.1	395.8	325.0	151.2	6.1	17,004.1
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 503.7	$ 340.0	$ 21.5	$ 18.7	$ 10.6	$ 0.5	$ 895.0
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 503.7	$ 340.0	$ 21.5	$ 18.7	$ 10.6	$ 0.5	$ 895.0
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	17,188.7	158.2	-	12,329.9	70,703.2	148,153.5	285,703.2	236,926.9	206,715.2	43,858.3	105,961.3	187,617.0	1,315,315.5
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.3
Total Energy Excl. CSPP (MWh)	47,242.8	23,351.4	25,715.8	39,416.0	101,509.9	212,072.7	353,339.5	298,204.3	228,725.2	75,042.5	135,704.4	224,534.3	1,764,858.8
Market Cost ($ x 1000)	$ 1,238.0	$ 9.3	$ -	$ 519.6	$ 2,928.6	$ 5,709.5	$ 18,115.1	$ 12,194.3	$ 10,464.0	$ 2,406.8	$ 6,665.8	$ 13,171.4	$ 73,422.7
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 2,786.9	$ 1,210.0	$ 981.9	$ 1,554.2	$ 4,103.8	$ 8,777.9	$ 21,702.0	$ 15,419.6	$ 11,613.7	$ 4,025.3	$ 8,519.3	$ 15,465.1	$ 96,159.5
Surplus Sales													
Energy (MWh)	39,080.7	128,042.8	250,849.8	105,599.8	121,120.1	14,228.5	2,567.5	10,205.9	50,326.0	97,699.2	56,381.6	11,978.8	888,080.7
Revenue Including Transmission Costs ($ x 1000)	$ 2,557.0	$ 6,064.0	$ 10,133.6	$ 3,603.2	$ 2,966.8	$ 335.8	$ 79.1	$ 314.7	$ 1,538.3	$ 3,386.2	$ 2,296.5	$ 545.7	$ 33,821.0
Transmission Costs ($ x 1000)	$ 39.1	$ 128.0	$ 250.8	$ 105.6	$ 121.1	$ 14.2	$ 2.6	$ 10.2	$ 50.3	$ 97.7	$ 56.4	$ 12.0	$ 888.1
Revenue Excluding Transmission Costs ($ x 1000)	$ 2,517.9	$ 5,936.0	$ 9,882.8	$ 3,497.6	$ 2,845.7	$ 321.6	$ 76.5	$ 304.5	$ 1,488.0	$ 3,288.5	$ 2,240.1	$ 533.7	$ 32,932.9
Net Power Supply Expense ($ x 1000)	$ 14,545.9	$ 8,158.8	$ 5,359.2	$ 9,350.6	$ 11,898.4	$ 20,719.0	$ 38,265.0	$ 30,663.3	$ 24,207.9	$ 15,190.8	$ 20,235.4	$ 29,276.9	$ 227,871.3

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
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1995

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	587,038.7	822,808.5	779,103.1	848,653.3	1,227,416.1	1,332,849.3	790,918.2	641,554.9	557,240.8	512,353.8	473,292.8	871,663.4	9,444,893.1
Bridger													
Energy (MWh)	470,742.4	412,028.2	460,881.6	354,915.7	311,920.3	328,735.5	465,528.8	467,571.1	447,360.9	464,502.8	455,557.1	470,742.4	5,110,486.7
Cost ($ x 1000)	$ 8,722.2	$ 7,642.6	$ 8,554.1	$ 6,618.4	$ 5,840.6	$ 6,169.4	$ 8,633.3	$ 8,668.1	$ 8,301.1	$ 8,615.9	$ 8,440.8	$ 8,722.2	$ 94,928.8
Boardman													
Energy (MWh)	27,329.8	20,307.9	27,835.4	2,726.4	-	14,866.7	36,452.2	35,875.0	34,865.2	36,359.2	35,964.1	36,363.9	308,945.7
Cost ($ x 1000)	$ 479.5	$ 370.7	$ 486.7	$ 47.6	$ -	$ 270.4	$ 609.7	$ 601.5	$ 584.2	$ 608.4	$ 599.9	$ 608.5	$ 5,267.0
Valmy													
Energy (MWh)	177,395.6	138,516.6	116,899.3	7,688.1	7,708.2	7,944.4	145,039.3	148,058.0	126,376.2	142,859.0	172,061.1	180,348.9	1,370,894.8
Cost ($ x 1000)	$ 4,524.2	$ 3,563.7	$ 3,039.6	$ 200.8	$ 202.7	$ 208.4	$ 3,744.8	$ 3,817.3	$ 3,274.7	$ 3,692.5	$ 4,383.6	$ 4,594.7	$ 35,247.1
Danskin													
Energy (MWh)	-	-	-	-	-	0.1	10,795.9	13,661.0	1,085.7	35.2	955.9	-	26,533.7
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 0.0	$ 374.8	$ 486.9	$ 39.5	$ 1.4	$ 44.6	$ -	$ 947.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 690.0	$ 802.1	$ 345.5	$ 316.6	$ 350.5	$ 315.3	$ 4,665.0
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	1,644.5	9,325.2	479.9	-	161.4	-	11,611.0
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 57.5	$ 333.6	$ 17.6	$ -	$ 7.6	$ -	$ 416.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 57.5	$ 333.6	$ 17.6	$ -	$ 7.6	$ -	$ 416.3
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	95,545.8	5,058.0	-	97.2	894.6	261.7	129,921.4	170,715.9	82,017.8	18,294.5	74,970.4	9,886.2	587,663.5
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	125,599.9	28,251.1	25,715.8	27,183.3	31,701.2	64,180.9	197,557.7	231,993.3	104,027.7	49,478.7	104,713.4	46,803.5	1,037,206.6
Market Cost ($ x 1000)	$ 3,595.0	$ 136.6	$ -	$ 2.4	$ 24.6	$ 6.8	$ 4,688.6	$ 5,913.8	$ 2,687.1	$ 625.5	$ 3,172.1	$ 453.2	$ 21,305.7
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 5,143.8	$ 1,337.2	$ 981.9	$ 1,037.0	$ 1,199.7	$ 3,075.2	$ 8,275.5	$ 9,139.1	$ 3,836.8	$ 2,244.0	$ 5,025.5	$ 2,746.8	$ 44,042.6
Surplus Sales													
Energy (MWh)	11,954.3	266,650.8	280,363.6	191,436.7	364,048.8	395,997.3	23,310.8	12,209.9	65,537.6	91,873.5	82,210.9	204,629.9	1,990,224.1
Revenue Including Transmission Costs ($ x 1000)	$ 450.2	$ 6,789.1	$ 6,994.6	$ 4,195.2	$ 7,089.5	$ 6,512.7	$ 596.2	$ 321.0	$ 1,549.6	$ 2,337.3	$ 2,332.6	$ 7,290.2	$ 46,458.2
Transmission Costs ($ x 1000)	$ 12.0	$ 266.7	$ 280.4	$ 191.4	$ 364.0	$ 396.0	$ 23.3	$ 12.2	$ 65.5	$ 91.9	$ 82.2	$ 204.6	$ 1,990.2
Revenue Excluding Transmission Costs ($ x 1000)	$ 438.2	$ 6,522.4	$ 6,714.2	$ 4,003.8	$ 6,725.4	$ 6,116.7	$ 572.9	$ 308.8	$ 1,484.1	$ 2,245.4	$ 2,250.4	$ 7,085.6	$ 44,468.0
Net Power Supply Expense ($ x 1000)	$ 18,746.8	$ 6,679.1	$ 6,663.5	$ 4,206.0	$ 832.8	$ 3,912.6	$ 21,438.0	$ 23,052.9	$ 14,875.8	$ 13,231.9	$ 16,557.6	$ 9,901.8	$ 140,098.9

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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,093,805.3	1,099,295.1	1,171,163.1	993,557.3	1,109,996.0	1,325,156.4	717,436.2	644,450.7	673,974.3	503,638.9	478,252.2	1,001,150.9	10,811,876.5
Bridger													
Energy (MWh)	462,491.7	353,506.1	245,348.5	196,657.9	203,769.0	211,987.1	363,308.9	366,761.6	297,141.9	365,802.8	430,062.3	470,557.0	3,967,394.7
Cost ($ x 1000)	$ 8,581.6	$ 6,622.6	$ 4,667.4	$ 3,709.8	$ 3,872.5	$ 4,038.7	$ 6,841.4	$ 6,896.5	$ 5,609.4	$ 6,909.3	$ 8,006.3	$ 8,719.0	$ 74,474.4
Boardman													
Energy (MWh)	21,427.3	15,103.1	8,675.9	668.0	-	-	26,668.4	30,103.1	32,217.2	36,792.0	34,089.9	34,065.3	239,810.2
Cost ($ x 1000)	$ 395.3	$ 287.5	$ 168.1	$ 13.0	$ -	$ -	$ 457.7	$ 514.2	$ 543.5	$ 614.6	$ 573.1	$ 575.7	$ 4,142.6
Valmy													
Energy (MWh)	151,152.8	180.4	-	-	-	-	23,274.6	16,929.3	2,225.3	4,615.1	51,135.6	142,350.7	391,863.9
Cost ($ x 1000)	$ 3,893.5	$ 5.1	$ -	$ -	$ -	$ -	$ 638.6	$ 463.6	$ 62.5	$ 130.2	$ 1,355.0	$ 3,679.0	$ 10,227.5
Danskin													
Energy (MWh)	-	-	-	0.2	0.5	36.4	8,090.8	9,540.8	2,836.5	1,057.3	1,198.9	-	22,761.4
Cost ($ x 1000)	$ -	$ -	$ -	$ 0.0	$ 0.0	$ 0.9	$ 206.3	$ 249.0	$ 75.8	$ 29.7	$ 40.7	$ -	$ 602.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 306.9	$ 521.5	$ 564.3	$ 381.7	$ 344.9	$ 346.6	$ 315.3	$ 4,320.2
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	1,251.1	6,690.5	1,857.3	395.9	35.8	-	10,230.4
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 32.1	$ 175.6	$ 49.9	$ 11.2	$ 1.2	$ -	$ 270.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 32.1	$ 175.6	$ 49.9	$ 11.2	$ 1.2	$ -	$ 270.1
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	-	2,107.4	3,464.2	8,185.8	17,806.2	13,552.5	416,959.4	400,315.0	183,811.5	170,874.5	151,367.9	-	1,368,444.4
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	30,054.1	25,300.5	29,180.0	35,271.9	48,612.8	77,471.6	484,595.7	461,592.4	205,821.5	202,058.8	181,110.9	36,917.3	1,817,987.6
Market Cost ($ x 1000)	$ -	$ 46.1	$ 72.7	$ 160.3	$ 332.1	$ 240.2	$ 8,928.0	$ 8,873.4	$ 4,183.0	$ 4,100.2	$ 4,337.3	$ -	$ 31,273.4
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 1,548.9	$ 1,246.8	$ 1,054.6	$ 1,194.9	$ 1,507.2	$ 3,308.6	$ 12,514.9	$ 12,098.7	$ 5,332.6	$ 5,718.7	$ 6,190.8	$ 2,293.6	$ 54,010.2
Surplus Sales													
Energy (MWh)	382,779.2	338,123.6	324,295.8	176,425.2	147,681.2	262,072.0	-	239.9	10,175.2	645.6	15,390.6	283,748.9	1,941,577.2
Revenue Including Transmission Costs ($ x 1000)	$ 9,825.6	$ 6,547.0	$ 5,515.9	$ 2,947.6	$ 2,224.8	$ 3,308.2	$ -	$ 6.5	$ 224.9	$ 13.7	$ 347.2	$ 7,847.1	$ 38,808.5
Transmission Costs ($ x 1000)	$ 382.8	$ 338.1	$ 324.3	$ 176.4	$ 147.7	$ 262.1	$ -	$ 0.2	$ 10.2	$ 0.6	$ 15.4	$ 283.7	$ 1,941.6
Revenue Excluding Transmission Costs ($ x 1000)	$ 9,442.9	$ 6,208.9	$ 5,191.6	$ 2,771.2	$ 2,077.1	$ 3,046.1	$ -	$ 6.3	$ 214.7	$ 13.1	$ 331.8	$ 7,563.3	$ 36,867.0
Net Power Supply Expense ($ x 1000)	$ 5,291.6	$ 2,240.4	$ 1,013.8	$ 2,452.4	$ 3,617.9	$ 4,608.0	$ 21,006.2	$ 20,706.5	$ 11,765.0	$ 13,715.7	$ 16,141.3	$ 8,019.3	$ 110,578.1

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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,263,127.8	1,082,442.1	1,157,551.8	953,306.8	1,101,132.7	1,222,835.2	1,123,226.7	872,836.2	927,235.4	715,609.9	594,889.8	861,360.2	11,875,554.5
Bridger													
Energy (MWh)	456,397.8	331,045.1	226,060.9	210,171.2	181,790.0	193,139.1	343,158.3	336,686.4	287,721.6	351,309.8	402,415.4	463,547.4	3,783,443.0
Cost ($ x 1000)	$ 8,477.7	$ 6,235.1	$ 4,298.3	$ 3,991.8	$ 3,458.5	$ 3,697.5	$ 6,477.3	$ 6,369.8	$ 5,460.1	$ 6,651.0	$ 7,535.1	$ 8,599.6	$ 71,251.7
Boardman													
Energy (MWh)	20,296.5	13,226.7	3,360.2	648.0	-	-	22,381.6	29,532.6	29,048.3	35,111.5	33,850.3	32,711.2	220,166.9
Cost ($ x 1000)	$ 379.2	$ 254.1	$ 65.6	$ 13.1	$ -	$ -	$ 386.5	$ 506.0	$ 494.8	$ 590.6	$ 569.7	$ 556.3	$ 3,816.0
Valmy													
Energy (MWh)	121,250.6	-	-	-	-	-	5,006.4	15,030.8	-	-	17,438.0	113,817.0	272,542.7
Cost ($ x 1000)	$ 3,147.1	$ -	$ -	$ -	$ -	$ -	$ 141.3	$ 415.6	$ -	$ -	$ 474.5	$ 2,966.7	$ 7,145.1
Danskin													
Energy (MWh)	-	-	-	2.4	6.1	838.4	5,369.1	7,858.4	3,398.4	2,278.3	884.4	2.2	20,637.8
Cost ($ x 1000)	$ -	$ -	$ -	$ 0.1	$ 0.1	$ 20.1	$ 129.9	$ 194.4	$ 86.1	$ 60.7	$ 28.4	$ 0.1	$ 519.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 306.0	$ 315.4	$ 326.0	$ 445.1	$ 509.6	$ 392.0	$ 375.9	$ 334.4	$ 315.3	$ 4,237.7
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	2.9	760.6	6,346.8	1,874.9	742.1	211.7	-	9,939.0
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 0.1	$ 18.5	$ 158.0	$ 47.8	$ 19.9	$ 6.9	$ -	$ 251.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ 0.1	$ 18.5	$ 158.0	$ 47.8	$ 19.9	$ 6.9	$ -	$ 251.2
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	-	1,721.1	4,112.4	13,442.2	23,296.7	23,801.0	92,401.3	217,949.9	51,899.4	33,269.6	100,065.5	11,182.9	573,141.9
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	30,054.1	24,914.2	29,828.3	40,528.3	54,103.3	87,720.1	160,037.6	279,227.3	73,909.4	64,453.8	129,808.5	48,100.3	1,022,685.1
Market Cost ($ x 1000)	$ -	$ 30.6	$ 83.6	$ 255.6	$ 406.9	$ 401.8	$ 1,841.8	$ 4,468.8	$ 1,187.4	$ 727.0	$ 2,705.1	$ 359.7	$ 12,468.3
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 1,548.9	$ 1,231.2	$ 1,065.6	$ 1,290.2	$ 1,582.0	$ 3,470.1	$ 5,428.6	$ 7,694.1	$ 2,337.1	$ 2,345.5	$ 4,558.6	$ 2,653.3	$ 35,205.2
Surplus Sales													
Energy (MWh)	514,974.7	296,366.6	286,729.5	154,926.5	122,335.1	151,956.2	35,314.6	11,689.8	117,289.3	55,790.3	19,003.0	118,246.0	1,884,621.6
Revenue Including Transmission Costs ($ x 1000)	$ 11,881.7	$ 5,611.6	$ 4,612.2	$ 2,431.2	$ 1,712.9	$ 2,047.6	$ 710.1	$ 297.6	$ 2,212.5	$ 1,215.6	$ 430.3	$ 2,976.0	$ 36,139.5
Transmission Costs ($ x 1000)	$ 515.0	$ 296.4	$ 286.7	$ 154.9	$ 122.3	$ 152.0	$ 35.3	$ 11.7	$ 117.3	$ 55.8	$ 19.0	$ 118.2	$ 1,884.6
Revenue Excluding Transmission Costs ($ x 1000)	$ 11,366.7	$ 5,315.3	$ 4,325.5	$ 2,276.3	$ 1,590.6	$ 1,895.7	$ 674.8	$ 285.9	$ 2,095.2	$ 1,159.8	$ 411.3	$ 2,857.7	$ 34,254.9
Net Power Supply Expense ($ x 1000)	$ 2,501.3	$ 2,692.5	$ 1,419.2	$ 3,324.8	$ 3,765.3	$ 5,598.1	$ 12,222.5	$ 15,367.3	$ 6,636.6	$ 8,823.0	$ 13,067.8	$ 12,233.6	$ 87,651.9

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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	991,436.4	1,118,960.8	1,149,474.7	1,216,218.2	1,260,846.9	1,254,042.7	762,271.3	678,452.3	660,564.5	583,459.9	540,611.3	832,873.2	11,049,212.1
Bridger													
Energy (MWh)	470,742.4	419,518.0	455,001.2	333,126.9	298,321.4	340,462.3	456,146.5	461,919.0	414,349.3	455,168.7	455,188.7	470,742.4	5,030,686.9
Cost ($ x 1000)	$ 8,722.2	$ 7,781.5	$ 8,453.9	$ 6,227.4	$ 5,608.8	$ 6,394.7	$ 8,462.2	$ 8,571.8	$ 7,738.5	$ 8,456.8	$ 8,434.6	$ 8,722.2	$ 93,574.4
Boardman													
Energy (MWh)	29,428.3	21,287.6	28,024.4	2,905.0	-	26,025.6	36,913.2	35,875.0	33,693.8	35,430.1	32,078.1	32,982.2	314,643.4
Cost ($ x 1000)	$ 509.5	$ 384.6	$ 489.4	$ 50.1	$ -	$ 455.1	$ 616.3	$ 601.5	$ 567.5	$ 595.1	$ 544.4	$ 560.2	$ 5,373.8
Valmy													
Energy (MWh)	177,293.6	112,426.7	60,773.9	3,223.3	-	6,978.6	135,062.4	128,422.6	67,787.0	130,034.3	157,298.8	179,267.8	1,158,568.9
Cost ($ x 1000)	$ 4,521.8	$ 2,927.0	$ 1,590.4	$ 90.7	$ -	$ 183.8	$ 3,489.9	$ 3,327.7	$ 1,766.7	$ 3,365.4	$ 4,032.2	$ 4,568.9	$ 29,864.3
Danskin													
Energy (MWh)	-	-	-	-	-	-	21,969.2	11,693.0	608.9	162.2	29.6	-	34,463.0
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 716.1	$ 392.0	$ 20.8	$ 5.8	$ 1.3	$ -	$ 1,136.0
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 1,031.3	$ 707.2	$ 326.8	$ 321.1	$ 307.2	$ 315.3	$ 4,853.9
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	6,514.3	8,088.9	211.5	30.1	-	-	14,844.8
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 213.8	$ 271.7	$ 7.3	$ 1.1	$ -	$ -	$ 493.9
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 213.8	$ 271.7	$ 7.3	$ 1.1	$ -	$ -	$ 493.9
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	-	-	-	-	934.1	244.0	148,331.8	163,096.0	63,440.7	5,920.1	44,700.1	11,234.1	437,900.8
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	31,740.7	64,163.1	215,968.1	224,373.4	85,450.7	37,104.3	74,443.1	48,151.4	887,444.0
Market Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ 23.3	$ 5.9	$ 6,696.5	$ 5,410.8	$ 1,847.3	$ 185.6	$ 1,639.9	$ 483.1	$ 16,292.5
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,198.4	$ 3,074.3	$ 10,283.3	$ 8,636.1	$ 2,997.0	$ 1,804.1	$ 3,493.3	$ 2,776.7	$ 39,029.3
Surplus Sales													
Energy (MWh)	322,802.7	540,124.8	588,918.5	532,829.4	376,211.9	339,092.8	10,219.4	12,995.5	56,767.0	127,674.5	99,154.6	162,724.7	3,169,515.7
Revenue Including Transmission Costs ($ x 1000)	$ 11,605.4	$ 12,573.2	$ 13,080.1	$ 10,662.0	$ 6,271.0	$ 6,556.2	$ 253.2	$ 340.0	$ 1,360.9	$ 3,216.6	$ 2,506.0	$ 4,800.1	$ 73,224.6
Transmission Costs ($ x 1000)	$ 322.8	$ 540.1	$ 588.9	$ 532.8	$ 376.2	$ 339.1	$ 10.2	$ 13.0	$ 56.8	$ 127.7	$ 99.2	$ 162.7	$ 3,169.5
Revenue Excluding Transmission Costs ($ x 1000)	$ 11,282.6	$ 12,033.1	$ 12,491.2	$ 10,129.2	$ 5,894.8	$ 6,217.1	$ 242.9	$ 327.0	$ 1,304.1	$ 3,088.9	$ 2,406.9	$ 4,637.4	$ 70,055.1
Net Power Supply Expense ($ x 1000)	$ 4,335.0	$ 548.0	$ (660.3)	$ (2,420.5)	$ 1,227.7	$ 4,196.7	$ 23,853.9	$ 21,789.0	$ 12,099.5	$ 11,454.7	$ 14,404.8	$ 12,305.9	$ 103,134.5

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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	1,039,572.2	1,110,929.9	1,162,991.3	986,300.0	1,023,480.0	1,257,621.3	707,589.9	643,036.8	604,759.5	514,811.1	504,888.7	750,639.5	10,306,620.1
Bridger													
Energy (MWh)	469,146.2	406,073.9	454,626.3	336,364.5	307,036.9	336,839.5	454,718.2	453,810.2	403,983.7	440,104.8	455,270.5	470,533.7	4,988,508.4
Cost ($ x 1000)	$ 8,695.0	$ 7,541.1	$ 8,447.5	$ 6,291.0	$ 5,757.3	$ 6,344.2	$ 8,449.1	$ 8,422.3	$ 7,561.9	$ 8,200.0	$ 8,435.9	$ 8,718.6	$ 92,864.0
Boardman													
Energy (MWh)	23,064.0	20,545.4	27,254.1	2,691.3	-	14,395.5	34,183.0	35,478.8	31,483.4	30,335.1	28,447.6	32,892.2	280,770.5
Cost ($ x 1000)	$ 415.8	$ 374.1	$ 478.5	$ 47.1	$ -	$ 261.0	$ 577.3	$ 595.8	$ 535.9	$ 522.4	$ 492.6	$ 558.9	$ 4,859.4
Valmy													
Energy (MWh)	162,705.0	116,279.7	54,929.5	-	-	-	126,716.7	133,039.7	42,218.1	99,948.6	152,762.3	179,322.3	1,067,921.9
Cost ($ x 1000)	$ 4,173.6	$ 3,027.7	$ 1,438.5	$ -	$ -	$ -	$ 3,281.9	$ 3,437.6	$ 1,103.8	$ 2,590.9	$ 3,925.6	$ 4,570.2	$ 27,549.8
Danskin													
Energy (MWh)	-	-	-	-	-	-	6,995.5	11,276.9	-	-	-	-	18,272.4
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 229.1	$ 380.3	$ -	$ -	$ -	$ -	$ 609.5
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 544.4	$ 695.6	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 4,327.3
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	1,068.1	9,043.1	-	-	-	-	10,111.2
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 35.2	$ 305.2	$ -	$ -	$ -	$ -	$ 340.5
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 35.2	$ 305.2	$ -	$ -	$ -	$ -	$ 340.5
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	-	-	-	182.3	12,553.5	5,004.1	228,634.6	196,812.0	119,548.5	38,059.1	60,896.2	34,581.1	696,271.5
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	30,054.1	23,193.1	25,715.8	27,268.4	43,360.1	68,923.2	296,271.0	258,089.5	141,558.5	69,243.3	90,639.2	71,498.4	1,145,814.7
Market Cost ($ x 1000)	$ -	$ -	$ -	$ 4.3	$ 317.4	$ 116.1	$ 6,615.2	$ 6,399.3	$ 3,179.2	$ 1,026.5	$ 2,143.1	$ 1,469.5	$ 21,270.6
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,038.8	$ 1,492.5	$ 3,184.5	$ 10,202.0	$ 9,624.6	$ 4,328.9	$ 2,644.9	$ 3,996.6	$ 3,763.1	$ 44,007.5
Surplus Sales													
Energy (MWh)	348,389.4	521,760.7	595,445.3	302,894.1	159,179.9	325,199.9	2,916.6	7,946.5	18,104.4	40,727.6	71,513.3	103,594.0	2,497,671.8
Revenue Including Transmission Costs ($ x 1000)	$ 10,983.4	$ 12,114.5	$ 13,272.1	$ 6,158.1	$ 2,979.5	$ 5,468.9	$ 70.2	$ 211.9	$ 402.6	$ 927.2	$ 1,691.7	$ 2,919.6	$ 57,199.9
Transmission Costs ($ x 1000)	$ 348.4	$ 521.8	$ 595.4	$ 302.9	$ 159.2	$ 325.2	$ 2.9	$ 7.9	$ 18.1	$ 40.7	$ 71.5	$ 103.6	$ 2,497.7
Revenue Excluding Transmission Costs ($ x 1000)	$ 10,635.0	$ 11,592.8	$ 12,676.7	$ 5,855.2	$ 2,820.4	$ 5,143.7	$ 67.2	$ 203.9	$ 384.5	$ 886.5	$ 1,620.2	$ 2,816.0	$ 54,702.2
Net Power Supply Expense ($ x 1000)	$ 4,513.5	$ 838.1	$ (1,015.0)	$ 1,827.6	$ 4,744.7	$ 4,951.9	$ 23,022.7	$ 22,877.3	$ 13,451.8	$ 13,387.1	$ 15,536.5	$ 15,110.1	$ 119,246.3

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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	763,261.3	1,123,777.4	1,084,839.0	1,157,465.4	834,764.6	682,956.7	582,894.0	570,497.6	476,214.6	525,241.2	423,682.5	497,044.7	8,722,639.0
Bridger													
Energy (MWh)	470,742.4	424,454.3	470,235.8	376,709.0	339,777.5	370,026.8	470,618.4	470,209.9	453,468.6	470,408.7	455,557.1	470,742.4	5,242,950.9
Cost ($ x 1000)	$ 8,722.2	$ 7,865.6	$ 8,713.6	$ 6,989.9	$ 6,315.3	$ 6,909.8	$ 8,720.1	$ 8,713.1	$ 8,405.2	$ 8,716.5	$ 8,440.8	$ 8,722.2	$ 97,234.4
Boardman													
Energy (MWh)	30,456.9	27,605.9	33,527.8	3,142.3	-	26,283.5	36,828.4	36,150.7	35,033.3	36,012.8	33,344.4	34,430.6	332,816.6
Cost ($ x 1000)	$ 524.2	$ 474.8	$ 568.0	$ 53.5	$ -	$ 455.9	$ 615.1	$ 605.4	$ 586.6	$ 603.4	$ 562.5	$ 580.9	$ 5,630.3
Valmy													
Energy (MWh)	179,234.4	149,767.8	170,147.9	106,620.6	120,528.8	132,284.4	179,520.6	179,918.0	166,235.4	179,794.1	174,439.5	180,049.0	1,918,540.5
Cost ($ x 1000)	$ 4,568.1	$ 3,832.1	$ 4,351.2	$ 2,762.6	$ 3,114.9	$ 3,423.7	$ 4,574.9	$ 4,584.4	$ 4,248.4	$ 4,581.4	$ 4,444.3	$ 4,587.6	$ 49,073.6
Danskin													
Energy (MWh)	-	-	-	-	-	-	21,348.7	10,992.7	609.7	2.2	-	-	32,953.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 850.9	$ 449.3	$ 25.5	$ 0.1	$ -	$ -	$ 1,325.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 1,166.1	$ 764.6	$ 331.5	$ 315.4	$ 305.9	$ 315.3	$ 5,043.6
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	6,166.1	6,338.2	4.5	-	-	-	12,508.8
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 247.5	$ 260.4	$ 0.2	$ -	$ -	$ -	$ 508.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 247.5	$ 260.4	$ 0.2	$ -	$ -	$ -	$ 508.2
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	11,682.7	-	-	-	34,880.8	97,622.5	264,495.7	215,542.1	123,761.3	13,732.2	102,113.7	192,024.3	1,055,855.3
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	41,736.8	23,193.1	25,715.8	27,086.1	65,687.4	161,541.6	332,132.0	276,819.5	145,771.3	44,916.4	131,856.7	228,941.6	1,505,398.4
Market Cost ($ x 1000)	$ 537.7	$ -	$ -	$ -	$ 1,074.1	$ 2,747.4	$ 11,879.4	$ 8,350.1	$ 4,744.9	$ 531.0	$ 4,508.9	$ 9,417.0	$ 43,790.4
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 2,086.5	$ 1,200.7	$ 981.9	$ 1,034.6	$ 2,249.2	$ 5,815.7	$ 15,466.3	$ 11,575.4	$ 5,894.5	$ 2,149.4	$ 6,362.4	$ 11,710.6	$ 66,527.2
Surplus Sales													
Energy (MWh)	109,279.7	593,537.0	654,394.6	621,293.3	146,061.2	20,513.4	4,882.4	15,098.1	71,438.8	142,660.1	58,385.3	9,916.1	2,447,460.0
Revenue Including Transmission Costs ($ x 1000)	$ 4,821.9	$ 17,909.8	$ 18,066.6	$ 13,905.8	$ 3,386.7	$ 499.0	$ 118.1	$ 389.0	$ 1,798.6	$ 3,958.2	$ 1,590.0	$ 275.4	$ 66,719.0
Transmission Costs ($ x 1000)	$ 109.3	$ 593.5	$ 654.4	$ 621.3	$ 146.1	$ 20.5	$ 4.9	$ 15.1	$ 71.4	$ 142.7	$ 58.4	$ 9.9	$ 2,447.5
Revenue Excluding Transmission Costs ($ x 1000)	$ 4,712.7	$ 17,316.2	$ 17,412.2	$ 13,284.5	$ 3,240.6	$ 478.5	$ 113.2	$ 373.9	$ 1,727.2	$ 3,815.5	$ 1,531.6	$ 265.4	$ 64,271.6
Net Power Supply Expense ($ x 1000)	$ 11,503.6	$ (3,655.7)	$ (2,482.2)	$ (2,138.1)	$ 8,754.1	$ 16,432.7	$ 30,676.8	$ 26,129.4	$ 17,739.2	$ 12,550.7	$ 18,584.4	$ 25,651.0	$ 159,745.7

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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	479,652.2	483,975.8	625,174.3	558,058.8	613,697.4	495,685.9	534,754.6	487,553.0	349,615.5	404,848.5	406,555.7	480,153.9	5,919,725.6
Bridger													
Energy (MWh)	470,742.4	425,186.7	470,742.4	383,427.2	353,056.8	392,749.4	470,742.4	470,742.4	455,557.1	470,742.4	455,557.1	470,742.4	5,289,988.6
Cost ($ x 1000)	$ 8,722.2	$ 7,878.1	$ 8,722.2	$ 7,104.4	$ 6,541.6	$ 7,297.1	$ 8,722.2	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 98,036.0
Boardman													
Energy (MWh)	37,529.9	34,427.3	38,214.1	3,610.5	-	29,751.3	39,224.0	38,458.3	36,799.6	38,748.3	37,489.6	35,782.1	370,034.9
Cost ($ x 1000)	$ 625.1	$ 572.2	$ 634.9	$ 60.2	$ -	$ 508.3	$ 649.3	$ 638.3	$ 611.8	$ 642.5	$ 621.6	$ 600.2	$ 6,164.3
Valmy													
Energy (MWh)	180,348.9	162,670.9	179,460.5	150,328.0	152,701.1	165,624.2	180,348.9	180,348.9	174,531.2	180,348.9	174,531.2	180,303.7	2,061,546.8
Cost ($ x 1000)	$ 4,594.7	$ 4,144.7	$ 4,573.5	$ 3,832.2	$ 3,896.6	$ 4,233.9	$ 4,594.7	$ 4,594.7	$ 4,446.5	$ 4,594.7	$ 4,446.5	$ 4,593.6	$ 52,546.3
Danskin													
Energy (MWh)	-	-	-	-	-	304.7	41,920.2	27,154.6	6,664.0	4,611.7	1,321.0	-	81,976.1
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 15.6	$ 2,163.6	$ 1,437.3	$ 361.3	$ 263.7	$ 92.2	$ -	$ 4,333.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 321.5	$ 2,478.8	$ 1,752.5	$ 667.2	$ 579.0	$ 398.2	$ 315.3	$ 8,051.5
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	16,065.6	15,076.6	474.6	589.6	93.3	-	32,299.9
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 835.2	$ 802.6	$ 25.9	$ 34.0	$ 6.6	$ -	$ 1,704.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 835.2	$ 802.6	$ 25.9	$ 34.0	$ 6.6	$ -	$ 1,704.3
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	178,107.2	42,751.4	-	15,402.9	147,875.3	210,344.0	276,137.5	260,132.7	208,942.6	63,403.0	109,666.9	206,098.1	1,718,861.7
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.3
Total Energy Excl. CSPP (MWh)	208,161.3	65,944.5	25,715.8	42,489.0	178,681.9	274,263.2	343,773.9	321,410.1	230,952.6	94,587.2	139,409.9	243,015.5	2,168,405.0
Market Cost ($ x 1000)	$ 12,575.6	$ 2,154.8	$ -	$ 693.4	$ 6,237.6	$ 8,063.6	$ 22,476.2	$ 14,816.0	$ 10,775.0	$ 3,510.3	$ 6,913.6	$ 12,873.7	$ 101,089.8
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 14,124.5	$ 3,355.5	$ 981.9	$ 1,727.9	$ 7,412.7	$ 11,132.0	$ 26,063.1	$ 18,041.3	$ 11,924.6	$ 5,128.8	$ 8,767.0	$ 15,167.4	$ 123,826.7
Surplus Sales													
Energy (MWh)	282.6	16,943.7	209,235.5	88,183.5	83,440.1	5,799.1	2,203.9	4,915.3	48,695.9	80,761.4	54,462.9	8,705.4	603,629.3
Revenue Including Transmission Costs ($ x 1000)	$ 16.3	$ 775.9	$ 8,230.7	$ 3,064.5	$ 1,981.3	$ 135.6	$ 70.4	$ 148.5	$ 1,489.0	$ 2,774.4	$ 2,209.3	$ 325.3	$ 21,221.2
Transmission Costs ($ x 1000)	$ 0.3	$ 16.9	$ 209.2	$ 88.2	$ 83.4	$ 5.8	$ 2.2	$ 4.9	$ 48.7	$ 80.8	$ 54.5	$ 8.7	$ 603.6
Revenue Excluding Transmission Costs ($ x 1000)	$ 16.0	$ 759.0	$ 8,021.5	$ 2,976.3	$ 1,897.8	$ 129.8	$ 68.2	$ 143.6	$ 1,440.3	$ 2,693.7	$ 2,154.9	$ 316.6	$ 20,617.6
Net Power Supply Expense ($ x 1000)	$ 28,365.8	$ 15,478.8	$ 7,206.3	$ 10,054.3	$ 16,268.3	$ 23,362.9	$ 43,275.1	$ 34,408.1	$ 24,676.6	$ 17,007.5	$ 20,525.9	$ 29,082.0	$ 269,711.5

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	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	475,657.5	568,874.1	585,451.1	734,902.4	666,622.1	586,116.0	507,218.0	513,524.6	358,104.8	426,129.9	402,381.8	469,070.9	6,294,053.1
Bridger													
Energy (MWh)	470,742.4	425,186.7	470,406.4	383,427.2	347,675.4	384,669.7	470,742.4	470,714.7	455,217.9	470,742.4	455,557.1	470,742.4	5,275,824.5
Cost ($ x 1000)	$ 8,722.2	$ 7,878.1	$ 8,716.5	$ 7,104.4	$ 6,449.9	$ 7,159.4	$ 8,722.2	$ 8,721.7	$ 8,435.1	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 97,794.6
Boardman													
Energy (MWh)	30,137.9	26,518.1	29,686.0	3,362.7	-	25,688.1	37,045.9	36,906.3	34,867.5	36,049.2	33,824.7	36,594.0	330,680.4
Cost ($ x 1000)	$ 519.6	$ 459.3	$ 513.2	$ 56.7	$ -	$ 444.6	$ 618.2	$ 616.2	$ 584.2	$ 604.0	$ 569.3	$ 611.7	$ 5,596.9
Valmy													
Energy (MWh)	179,776.8	160,039.2	170,556.3	148,598.2	143,908.0	157,130.5	178,939.9	180,148.1	174,476.9	179,779.1	174,404.0	180,297.9	2,028,054.9
Cost ($ x 1000)	$ 4,581.0	$ 4,081.8	$ 4,361.0	$ 3,790.8	$ 3,686.8	$ 4,028.9	$ 4,561.1	$ 4,589.9	$ 4,445.2	$ 4,581.1	$ 4,443.5	$ 4,593.5	$ 51,744.7
Danskin													
Energy (MWh)	-	-	-	-	-	14.6	22,357.8	17,099.2	1,629.3	121.4	-	-	41,222.3
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 0.7	$ 1,064.4	$ 834.3	$ 81.5	$ 6.4	$ -	$ -	$ 1,987.3
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 306.6	$ 1,379.7	$ 1,149.6	$ 387.4	$ 321.7	$ 305.9	$ 315.3	$ 5,705.1
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	2,437.8	6,359.0	105.2	-	-	-	8,902.0
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 116.9	$ 312.2	$ 5.3	$ -	$ -	$ -	$ 434.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 116.9	$ 312.2	$ 5.3	$ -	$ -	$ -	$ 434.4
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	189,857.0	5,540.0	138.8	-	109,843.6	145,496.6	339,233.3	256,859.8	207,567.2	56,024.9	115,543.7	214,904.1	1,641,009.0
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	219,911.1	28,733.1	25,854.7	27,086.1	140,650.2	209,415.8	406,869.6	318,137.2	229,577.2	87,209.1	145,286.7	251,821.4	2,090,552.2
Market Cost ($ x 1000)	$ 10,292.7	$ 193.6	$ 5.0	$ -	$ 3,942.7	$ 4,999.8	$ 18,212.2	$ 12,131.4	$ 9,213.1	$ 2,535.5	$ 6,039.5	$ 12,752.6	$ 80,318.1
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 11,841.5	$ 1,394.3	$ 986.9	$ 1,034.6	$ 5,117.8	$ 8,068.1	$ 21,799.0	$ 15,356.7	$ 10,362.7	$ 4,154.0	$ 7,892.9	$ 15,046.3	$ 103,054.9
Surplus Sales													
Energy (MWh)	73.6	54,089.8	151,882.8	247,646.6	84,158.5	10,455.1	985.7	7,060.5	48,079.9	86,315.9	50,959.3	7,234.5	748,941.9
Revenue Including Transmission Costs ($ x 1000)	$ 2.7	$ 1,972.5	$ 4,614.4	$ 7,687.1	$ 1,910.7	$ 246.3	$ 26.7	$ 191.1	$ 1,242.8	$ 2,449.8	$ 1,594.3	$ 262.7	$ 22,201.0
Transmission Costs ($ x 1000)	$ 0.1	$ 54.1	$ 151.9	$ 247.6	$ 84.2	$ 10.5	$ 1.0	$ 7.1	$ 48.1	$ 86.3	$ 51.0	$ 7.2	$ 748.9
Revenue Excluding Transmission Costs ($ x 1000)	$ 2.6	$ 1,918.5	$ 4,462.6	$ 7,439.5	$ 1,826.5	$ 235.8	$ 25.7	$ 184.0	$ 1,194.7	$ 2,363.5	$ 1,543.3	$ 255.5	$ 21,452.1
Net Power Supply Expense ($ x 1000)	$ 25,977.0	$ 12,182.3	$ 10,430.3	$ 4,852.9	$ 13,743.3	$ 19,771.8	$ 37,171.4	$ 30,562.3	$ 23,025.2	$ 16,019.5	$ 20,109.2	$ 29,033.5	$ 242,878.6

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
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2003

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	523,323.8	551,572.7	533,573.7	597,348.6	840,877.3	734,828.8	496,938.5	515,947.7	369,274.1	414,434.8	400,280.0	473,297.6	6,451,697.7
Bridger													
Energy (MWh)	470,742.4	425,186.7	470,742.4	383,427.2	351,002.1	389,497.6	470,742.4	470,742.4	455,557.1	470,742.4	455,557.1	470,742.4	5,284,682.1
Cost ($ x 1000)	$ 8,722.2	$ 7,878.1	$ 8,722.2	$ 7,104.4	$ 6,506.6	$ 7,241.7	$ 8,722.2	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 97,945.6
Boardman													
Energy (MWh)	37,303.1	33,272.4	37,776.9	3,625.8	-	28,810.9	37,539.6	38,162.7	36,632.9	38,027.6	37,145.1	37,700.0	365,996.8
Cost ($ x 1000)	$ 621.9	$ 555.7	$ 628.6	$ 60.4	$ -	$ 494.9	$ 625.2	$ 634.1	$ 609.4	$ 632.2	$ 616.7	$ 627.5	$ 6,106.7
Valmy													
Energy (MWh)	180,348.9	162,895.8	179,482.0	150,480.3	141,165.7	160,552.6	180,338.1	180,299.3	174,531.2	180,273.6	174,531.2	180,348.9	2,045,247.8
Cost ($ x 1000)	$ 4,594.7	$ 4,150.1	$ 4,574.0	$ 3,835.8	$ 3,621.4	$ 4,112.8	$ 4,594.5	$ 4,593.5	$ 4,446.5	$ 4,592.9	$ 4,446.5	$ 4,594.7	$ 52,157.5
Danskin													
Energy (MWh)	-	-	-	-	-	-	27,954.1	25,202.8	4,480.0	1,524.3	1,004.0	108.5	60,273.8
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,413.0	$ 1,307.8	$ 237.9	$ 85.4	$ 68.6	$ 8.9	$ 3,121.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 1,728.2	$ 1,623.1	$ 543.8	$ 400.6	$ 374.6	$ 324.2	$ 6,839.5
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	4,533.1	12,564.3	455.1	10.1	67.0	-	17,629.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 230.8	$ 655.1	$ 24.3	$ 0.6	$ 4.6	$ -	$ 915.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 230.8	$ 655.1	$ 24.3	$ 0.6	$ 4.6	$ -	$ 915.4
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	135,827.8	9,501.2	3,318.5	7,367.2	10,999.3	54,564.7	339,837.3	239,158.0	194,949.4	61,036.2	114,201.8	209,611.6	1,380,373.1
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	165,881.9	32,694.3	29,034.3	34,453.3	41,805.9	118,483.9	407,473.6	300,435.5	216,959.4	92,220.4	143,944.8	246,528.9	1,829,916.3
Market Cost ($ x 1000)	$ 9,167.6	$ 447.2	$ 155.8	$ 302.5	$ 416.6	$ 2,045.0	$ 20,073.0	$ 13,512.8	$ 9,722.2	$ 3,181.0	$ 6,949.6	$ 13,680.2	$ 79,653.6
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 10,716.5	$ 1,647.8	$ 1,137.8	$ 1,337.1	$ 1,591.8	$ 5,113.3	$ 23,659.9	$ 16,738.1	$ 10,871.9	$ 4,799.5	$ 8,803.1	$ 15,973.8	$ 102,390.5
Surplus Sales													
Energy (MWh)	1,448.1	50,360.4	120,537.7	119,605.1	160,153.8	79,594.3	893.7	7,526.0	51,991.1	83,518.0	52,034.3	7,434.2	735,096.8
Revenue Including Transmission Costs ($ x 1000)	$ 95.1	$ 2,250.8	$ 4,385.3	$ 4,027.6	$ 4,604.9	$ 2,593.5	$ 26.2	$ 227.5	$ 1,544.2	$ 2,695.0	$ 2,037.6	$ 305.6	$ 24,793.4
Transmission Costs ($ x 1000)	$ 1.4	$ 50.4	$ 120.5	$ 119.6	$ 160.2	$ 79.6	$ 0.9	$ 7.5	$ 52.0	$ 83.5	$ 52.0	$ 7.4	$ 735.1
Revenue Excluding Transmission Costs ($ x 1000)	$ 93.6	$ 2,200.4	$ 4,264.8	$ 3,908.0	$ 4,444.8	$ 2,513.9	$ 25.3	$ 220.0	$ 1,492.2	$ 2,611.5	$ 1,985.6	$ 298.2	$ 24,058.3
Net Power Supply Expense ($ x 1000)	$ 24,876.9	$ 12,318.6	$ 11,113.1	$ 8,735.6	$ 7,590.3	$ 14,754.8	$ 39,535.5	$ 32,746.2	$ 23,444.6	$ 16,536.5	$ 20,700.7	$ 29,944.2	$ 242,296.9

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
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2004

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	440,977.9	512,212.4	744,447.4	652,025.6	734,947.8	575,662.0	488,173.0	493,407.6	354,605.5	411,249.4	399,792.4	464,168.3	6,271,669.4
Bridger													
Energy (MWh)	470,742.4	425,186.7	470,742.4	383,427.2	349,827.9	393,794.6	470,742.4	470,742.4	455,505.7	470,742.4	455,557.1	470,742.4	5,287,753.5
Cost ($ x 1000)	$ 8,722.2	$ 7,878.1	$ 8,722.2	$ 7,104.4	$ 6,486.6	$ 7,314.9	$ 8,722.2	$ 8,722.2	$ 8,440.0	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 97,997.9
Boardman													
Energy (MWh)	35,382.7	33,679.6	37,182.4	3,489.8	-	29,245.3	38,097.7	37,639.3	36,605.6	37,886.2	37,216.4	38,376.6	364,801.6
Cost ($ x 1000)	$ 594.5	$ 561.5	$ 620.1	$ 58.5	$ -	$ 501.1	$ 633.2	$ 626.7	$ 609.0	$ 630.2	$ 617.7	$ 637.2	$ 6,089.6
Valmy													
Energy (MWh)	180,327.8	162,623.4	179,302.2	148,714.8	141,400.0	162,725.4	180,340.7	180,252.5	174,466.6	180,240.5	174,531.2	180,348.9	2,045,274.2
Cost ($ x 1000)	$ 4,594.2	$ 4,143.6	$ 4,569.7	$ 3,793.6	$ 3,627.0	$ 4,164.7	$ 4,594.5	$ 4,592.4	$ 4,445.0	$ 4,592.1	$ 4,446.5	$ 4,594.7	$ 52,158.0
Danskin													
Energy (MWh)	-	-	-	-	-	72.9	33,471.7	20,698.6	5,927.2	1,080.7	1,427.6	624.9	63,303.6
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ 3.7	$ 1,694.6	$ 1,074.0	$ 315.2	$ 60.6	$ 97.8	$ 51.5	$ 3,297.4
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 309.6	$ 2,009.9	$ 1,389.3	$ 621.2	$ 375.9	$ 403.7	$ 366.7	$ 7,015.3
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	9,114.7	8,773.8	396.3	67.1	70.4	22.1	18,444.4
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 464.9	$ 458.2	$ 21.2	$ 3.8	$ 4.9	$ 1.8	$ 954.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 464.9	$ 458.2	$ 21.2	$ 3.8	$ 4.9	$ 1.8	$ 954.8
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	218,973.0	38,594.8	-	1,309.1	62,684.9	143,415.9	337,776.5	268,721.7	204,609.8	63,232.4	114,539.8	217,722.2	1,671,580.0
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.3
Total Energy Excl. CSPP (MWh)	249,027.1	61,787.9	25,715.8	28,395.2	93,491.5	207,335.0	405,412.8	329,999.1	226,619.8	94,416.6	144,282.8	254,639.5	2,121,123.2
Market Cost ($ x 1000)	$ 14,273.5	$ 1,914.3	$ -	$ 53.0	$ 2,419.0	$ 5,500.4	$ 22,380.0	$ 13,846.1	$ 10,207.9	$ 3,287.2	$ 7,054.8	$ 14,589.7	$ 95,526.0
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 15,822.4	$ 3,115.0	$ 981.9	$ 1,087.5	$ 3,594.2	$ 8,568.8	$ 25,966.8	$ 17,071.4	$ 11,357.5	$ 4,905.7	$ 8,908.2	$ 16,883.3	$ 118,262.8
Surplus Sales													
Energy (MWh)	305.9	40,228.5	327,318.5	166,322.5	104,970.1	16,255.8	727.4	5,684.7	48,228.0	81,967.7	52,382.9	7,630.4	852,022.4
Revenue Including Transmission Costs ($ x 1000)	$ 14.6	$ 1,867.0	$ 12,561.9	$ 5,438.0	$ 2,513.8	$ 396.0	$ 20.8	$ 168.8	$ 1,432.8	$ 2,648.0	$ 2,046.7	$ 330.2	$ 29,438.7
Transmission Costs ($ x 1000)	$ 0.3	$ 40.2	$ 327.3	$ 166.3	$ 105.0	$ 16.3	$ 0.7	$ 5.7	$ 48.2	$ 82.0	$ 52.4	$ 7.6	$ 852.0
Revenue Excluding Transmission Costs ($ x 1000)	$ 14.3	$ 1,826.8	$ 12,234.6	$ 5,271.7	$ 2,408.8	$ 379.8	$ 20.1	$ 163.2	$ 1,384.6	$ 2,566.0	$ 1,994.4	$ 322.6	$ 28,586.7
Net Power Supply Expense ($ x 1000)	$ 30,034.3	$ 14,158.7	$ 2,974.6	$ 7,078.2	$ 11,614.2	$ 20,479.3	$ 42,371.4	$ 32,697.0	$ 24,109.3	$ 16,663.8	$ 20,827.5	$ 30,883.4	$ 253,891.7

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
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2005

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	428,978.9	492,106.7	478,742.7	693,316.6	991,172.4	649,222.8	508,971.9	505,069.5	448,005.3	550,042.3	468,951.1	697,155.5	6,911,735.6
Bridger													
Energy (MWh)	470,742.4	425,186.7	470,742.4	383,184.8	346,950.2	382,984.7	470,742.4	470,742.4	455,486.9	470,742.4	455,557.1	470,742.4	5,273,804.5
Cost ($ x 1000)	$ 8,722.2	$ 7,878.1	$ 8,722.2	$ 7,100.2	$ 6,437.6	$ 7,130.7	$ 8,722.2	$ 8,722.2	$ 8,439.6	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 97,760.2
Boardman													
Energy (MWh)	35,211.4	33,684.1	37,038.7	3,440.8	-	28,776.0	38,107.0	37,501.6	36,097.7	37,629.1	37,010.8	37,956.2	362,453.3
Cost ($ x 1000)	$ 592.0	$ 561.6	$ 618.1	$ 57.8	$ -	$ 494.4	$ 633.3	$ 624.7	$ 601.8	$ 626.5	$ 614.8	$ 631.2	$ 6,056.1
Valmy													
Energy (MWh)	180,271.0	162,607.1	177,153.6	146,425.2	139,125.8	159,567.9	180,348.9	180,346.3	174,488.8	180,096.4	174,531.2	180,348.9	2,035,311.2
Cost ($ x 1000)	$ 4,592.9	$ 4,143.2	$ 4,518.4	$ 3,739.0	$ 3,572.9	$ 4,089.4	$ 4,594.7	$ 4,594.7	$ 4,445.5	$ 4,588.7	$ 4,446.5	$ 4,594.7	$ 51,920.4
Danskin													
Energy (MWh)	31.9	-	-	-	-	-	35,582.9	20,466.3	2,771.5	403.1	782.4	-	60,038.1
Cost ($ x 1000)	$ 2.9	$ -	$ -	$ -	$ -	$ -	$ 1,627.3	$ 959.2	$ 133.1	$ 20.4	$ 48.3	$ -	$ 2,791.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 318.2	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 1,942.6	$ 1,274.4	$ 439.0	$ 335.7	$ 354.3	$ 315.3	$ 6,509.1
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	11,132.4	9,458.5	121.9	37.6	4.8	-	20,755.2
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 512.8	$ 446.1	$ 5.9	$ 1.9	$ 0.3	$ -	$ 967.0
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 512.8	$ 446.1	$ 5.9	$ 1.9	$ 0.3	$ -	$ 967.0
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	230,894.6	34,098.0	18,829.0	12.7	1,089.0	105,314.0	313,437.1	258,100.7	139,584.4	10,555.2	74,686.2	59,368.0	1,245,969.0
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	260,948.7	57,291.1	44,544.8	27,098.8	31,895.6	169,233.2	381,073.5	319,378.1	161,594.4	41,739.4	104,429.2	96,285.3	1,695,512.2
Market Cost ($ x 1000)	$ 13,808.3	$ 1,514.4	$ 798.2	$ 0.5	$ 37.6	$ 3,627.2	$ 21,541.4	$ 12,095.7	$ 6,242.0	$ 501.6	$ 4,174.4	$ 3,595.7	$ 67,936.8
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 15,357.2	$ 2,715.0	$ 1,780.1	$ 1,035.0	$ 1,212.8	$ 6,695.6	$ 25,128.2	$ 15,321.0	$ 7,391.6	$ 2,120.0	$ 6,027.8	$ 5,889.3	$ 90,673.7
Surplus Sales													
Energy (MWh)	32.2	15,614.1	78,150.6	203,736.1	294,446.9	37,205.1	1,333.3	7,134.1	72,667.6	166,975.0	80,771.7	81,196.0	1,039,262.7
Revenue Including Transmission Costs ($ x 1000)	$ 1.5	$ 628.9	$ 2,435.8	$ 6,090.4	$ 7,832.1	$ 972.2	$ 36.6	$ 194.2	$ 2,011.4	$ 5,475.3	$ 2,962.4	$ 3,513.3	$ 32,154.1
Transmission Costs ($ x 1000)	$ 0.0	$ 15.6	$ 78.2	$ 203.7	$ 294.4	$ 37.2	$ 1.3	$ 7.1	$ 72.7	$ 167.0	$ 80.8	$ 81.2	$ 1,039.3
Revenue Excluding Transmission Costs ($ x 1000)	$ 1.4	$ 613.3	$ 2,357.6	$ 5,886.6	$ 7,537.7	$ 935.0	$ 35.3	$ 187.1	$ 1,938.7	$ 5,308.3	$ 2,881.6	$ 3,432.1	$ 31,114.8
Net Power Supply Expense ($ x 1000)	$ 29,581.0	$ 14,971.9	$ 13,596.5	$ 6,351.3	$ 4,000.8	$ 17,781.0	$ 41,498.6	$ 30,796.0	$ 19,384.8	$ 11,086.6	$ 17,002.8	$ 16,720.5	$ 222,771.7

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
Hoku Annualized
2006

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	780,659.9	995,834.0	1,135,330.8	1,101,760.3	1,275,219.3	968,770.0	596,691.6	607,797.1	446,885.4	509,628.4	403,993.7	593,503.3	9,416,073.7
Bridger													
Energy (MWh)	470,742.4	424,211.2	466,584.2	346,986.8	311,213.1	359,173.5	468,522.3	467,837.1	441,879.8	465,693.1	455,557.1	470,742.4	5,149,143.0
Cost ($ x 1000)	$ 8,722.2	$ 7,861.5	$ 8,651.3	$ 6,483.3	$ 5,828.5	$ 6,724.8	$ 8,684.4	$ 8,672.7	$ 8,207.7	$ 8,636.1	$ 8,440.8	$ 8,722.2	$ 95,635.6
Boardman													
Energy (MWh)	27,662.9	25,992.2	28,681.7	2,639.7	-	25,671.6	35,882.0	36,365.3	34,425.2	36,331.8	35,518.1	36,735.5	325,905.9
Cost ($ x 1000)	$ 484.3	$ 451.8	$ 498.8	$ 46.3	$ -	$ 450.1	$ 601.6	$ 608.5	$ 577.9	$ 608.0	$ 593.5	$ 613.8	$ 5,534.5
Valmy													
Energy (MWh)	177,013.2	145,888.2	109,100.2	15,928.2	19,892.2	46,578.5	148,961.0	153,408.4	130,649.5	152,132.3	172,104.5	180,298.1	1,451,954.2
Cost ($ x 1000)	$ 4,515.1	$ 3,739.5	$ 2,835.4	$ 419.0	$ 522.4	$ 1,216.3	$ 3,845.9	$ 3,947.2	$ 3,380.8	$ 3,920.4	$ 4,385.1	$ 4,593.5	$ 37,320.5
Danskin													
Energy (MWh)	-	-	-	-	-	-	15,568.9	17,869.3	250.2	18.0	1,393.2	441.1	35,540.8
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 548.1	$ 646.3	$ 9.2	$ 0.7	$ 65.9	$ 25.0	$ 1,295.2
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 863.3	$ 961.5	$ 315.2	$ 316.0	$ 371.8	$ 340.3	$ 5,013.0
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	2,849.3	13,647.5	-	-	96.2	1.0	16,594.0
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 101.0	$ 495.2	$ -	$ -	$ 4.6	$ 0.1	$ 600.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 101.0	$ 495.2	$ -	$ -	$ 4.6	$ 0.1	$ 600.8
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	7,480.9	-	-	-	369.4	36,351.2	289,022.3	185,462.3	154,449.6	17,787.4	112,938.9	113,771.0	917,633.0
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	37,535.0	23,193.1	25,715.8	27,086.1	31,176.0	100,270.4	356,658.6	246,739.7	176,459.6	48,971.6	142,681.9	150,688.3	1,367,176.1
Market Cost ($ x 1000)	$ 244.4	$ -	$ -	$ -	$ 9.4	$ 827.1	$ 9,877.0	$ 7,091.1	$ 4,879.3	$ 617.0	$ 4,717.0	$ 5,442.8	$ 33,705.1
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 1,793.2	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,184.5	$ 3,895.5	$ 13,463.9	$ 10,316.4	$ 6,029.0	$ 2,235.4	$ 6,570.5	$ 7,736.4	$ 56,442.0
Surplus Sales													
Energy (MWh)	117,461.3	459,857.2	635,341.1	444,670.9	422,803.4	147,884.4	508.1	7,835.9	24,651.0	99,060.0	50,849.6	31,117.5	2,442,040.2
Revenue Including Transmission Costs ($ x 1000)	$ 4,553.3	$ 12,677.0	$ 14,959.4	$ 9,509.4	$ 7,709.4	$ 3,406.6	$ 11.3	$ 205.4	$ 578.4	$ 2,584.0	$ 1,383.7	$ 913.7	$ 58,491.5
Transmission Costs ($ x 1000)	$ 117.5	$ 459.9	$ 635.3	$ 444.7	$ 422.8	$ 147.9	$ 0.5	$ 7.8	$ 24.7	$ 99.1	$ 50.8	$ 31.1	$ 2,442.0
Revenue Excluding Transmission Costs ($ x 1000)	$ 4,435.8	$ 12,217.2	$ 14,324.0	$ 9,064.7	$ 7,286.6	$ 3,258.7	$ 10.8	$ 197.5	$ 553.7	$ 2,484.9	$ 1,332.8	$ 882.6	$ 56,049.4
Net Power Supply Expense ($ x 1000)	$ 11,394.2	$ 1,323.6	$ (1,041.3)	$ (775.6)	$ 564.0	$ 9,334.0	$ 27,549.2	$ 24,804.0	$ 17,956.9	$ 13,231.0	$ 19,033.5	$ 21,123.6	$ 144,497.1

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
Hoku Annualized
2007

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	625,980.5	595,762.4	634,970.9	546,446.1	685,902.8	561,465.0	538,621.0	540,805.5	374,434.7	442,110.3	394,374.8	490,027.4	6,430,901.4
Bridger													
Energy (MWh)	470,742.4	425,186.7	470,742.4	383,427.2	352,010.9	386,431.8	470,650.1	470,742.4	455,557.1	470,742.4	455,557.1	470,742.4	5,282,532.8
Cost ($ x 1000)	$ 8,722.2	$ 7,878.1	$ 8,722.2	$ 7,104.4	$ 6,523.8	$ 7,189.4	$ 8,720.6	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 8,440.8	$ 8,722.2	$ 97,909.0
Boardman													
Energy (MWh)	31,814.5	30,778.1	34,737.4	3,547.6	-	24,710.7	36,780.7	37,178.5	36,338.9	38,046.2	37,879.2	38,867.5	350,679.2
Cost ($ x 1000)	$ 543.5	$ 520.1	$ 585.2	$ 59.3	$ -	$ 430.6	$ 614.4	$ 620.1	$ 605.2	$ 632.5	$ 627.2	$ 644.2	$ 5,882.3
Valmy													
Energy (MWh)	179,434.5	162,402.5	177,185.1	148,229.2	145,012.8	158,261.3	178,973.6	180,268.1	174,531.2	180,337.3	174,435.1	180,348.9	2,039,419.6
Cost ($ x 1000)	$ 4,572.9	$ 4,138.3	$ 4,519.2	$ 3,782.0	$ 3,713.2	$ 4,058.2	$ 4,561.9	$ 4,592.8	$ 4,446.5	$ 4,594.4	$ 4,444.2	$ 4,594.7	$ 52,018.2
Danskin													
Energy (MWh)	-	-	-	-	-	-	19,018.8	16,634.0	3,166.1	2,152.0	2,548.2	1,753.9	45,273.0
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 939.6	$ 841.9	$ 164.3	$ 117.8	$ 170.2	$ 140.9	$ 2,374.7
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 1,254.8	$ 1,157.1	$ 470.2	$ 433.0	$ 476.2	$ 456.1	$ 6,092.5
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	1,393.4	5,935.6	252.1	242.0	233.7	37.4	8,094.2
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 69.3	$ 302.5	$ 13.2	$ 13.3	$ 15.7	$ 3.0	$ 417.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 69.3	$ 302.5	$ 13.2	$ 13.3	$ 15.7	$ 3.0	$ 417.1
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	50,722.3	2,431.2	-	20,503.5	97,080.9	164,241.2	313,635.5	233,628.9	193,250.7	44,054.5	116,755.3	193,074.5	1,429,378.3
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	80,776.4	25,624.4	25,715.8	47,589.6	127,887.5	228,160.3	381,271.8	294,906.3	215,260.7	75,238.7	146,498.3	229,991.8	1,878,921.6
Market Cost ($ x 1000)	$ 2,941.4	$ 102.3	$ -	$ 820.6	$ 3,833.5	$ 5,772.0	$ 15,564.5	$ 11,424.4	$ 9,392.0	$ 2,293.8	$ 7,082.8	$ 12,961.1	$ 72,188.4
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 4,490.3	$ 1,302.9	$ 981.9	$ 1,855.2	$ 5,008.7	$ 8,840.4	$ 19,151.3	$ 14,649.7	$ 10,541.6	$ 3,912.3	$ 8,936.3	$ 15,254.7	$ 94,925.3
Surplus Sales													
Energy (MWh)	12,596.1	84,492.6	213,279.9	79,509.7	96,116.7	6,449.6	2,083.6	10,641.8	53,642.0	95,153.7	51,031.3	10,477.1	715,474.2
Revenue Including Transmission Costs ($ x 1000)	$ 657.0	$ 3,491.3	$ 7,634.2	$ 2,441.6	$ 2,196.8	$ 149.3	$ 56.7	$ 317.0	$ 1,555.2	$ 3,121.9	$ 1,993.5	$ 455.5	$ 24,070.0
Transmission Costs ($ x 1000)	$ 12.6	$ 84.5	$ 213.3	$ 79.5	$ 96.1	$ 6.4	$ 2.1	$ 10.6	$ 53.6	$ 95.2	$ 51.0	$ 10.5	$ 715.5
Revenue Excluding Transmission Costs ($ x 1000)	$ 644.4	$ 3,406.8	$ 7,420.9	$ 2,362.1	$ 2,100.7	$ 142.8	$ 54.6	$ 306.3	$ 1,501.5	$ 3,026.7	$ 1,942.5	$ 445.0	$ 23,354.5
Net Power Supply Expense ($ x 1000)	$ 17,999.7	$ 10,719.9	$ 7,702.9	$ 10,744.7	$ 13,460.3	$ 20,681.7	$ 34,317.8	$ 29,738.0	$ 23,016.1	$ 15,281.0	$ 20,997.9	$ 29,229.9	$ 233,889.8

IPCO POWER SUPPLY EXPENSE FOR 2009 NORMALIZED LOADS OVER 81 WATER YEAR CONDITIONS
Hoku Annualized
2008

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Hydroelectric Generation (MWh)	466,080.8	613,841.1	625,432.9	631,110.6	964,659.4	885,539.9	610,900.1	579,082.3	410,326.3	472,943.6	408,652.0	473,258.5	7,141,827.5
Bridger													
Energy (MWh)	470,742.4	425,186.7	469,606.8	383,261.5	344,197.1	376,943.6	470,666.3	470,735.2	451,191.7	470,011.4	455,557.1	470,742.4	5,258,842.1
Cost ($ x 1000)	$ 8,722.2	$ 7,878.1	$ 8,702.8	$ 7,101.5	$ 6,390.6	$ 7,027.7	$ 8,720.9	$ 8,722.1	$ 8,366.4	$ 8,709.7	$ 8,440.8	$ 8,722.2	$ 97,505.2
Boardman													
Energy (MWh)	29,655.3	25,969.0	28,994.3	3,236.1	-	24,990.7	36,673.2	36,547.1	34,362.1	35,350.0	33,211.0	35,884.7	324,873.4
Cost ($ x 1000)	$ 512.7	$ 451.4	$ 503.3	$ 54.8	$ -	$ 434.6	$ 612.9	$ 611.1	$ 577.0	$ 594.0	$ 560.6	$ 601.6	$ 5,514.0
Valmy													
Energy (MWh)	179,632.0	158,552.1	162,963.2	147,250.2	137,902.0	150,078.4	179,666.3	179,976.7	173,695.8	179,185.0	174,326.7	180,108.5	2,003,336.8
Cost ($ x 1000)	$ 4,577.6	$ 4,046.4	$ 4,179.8	$ 3,758.6	$ 3,543.7	$ 3,853.6	$ 4,578.4	$ 4,585.8	$ 4,426.5	$ 4,566.9	$ 4,441.6	$ 4,589.0	$ 51,148.0
Danskin													
Energy (MWh)	-	-	-	-	-	-	15,505.7	12,320.2	540.9	-	-	21.0	28,387.7
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 681.3	$ 554.8	$ 25.0	$ -	$ -	$ 1.5	$ 1,262.5
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 315.3	$ 3,717.9
Total Cost	$ 315.3	$ 287.3	$ 315.3	$ 305.9	$ 315.3	$ 305.9	$ 996.5	$ 870.1	$ 330.9	$ 315.3	$ 305.9	$ 316.8	$ 4,980.4
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	828.3	4,403.9	13.5	-	-	-	5,245.7
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 36.7	$ 199.5	$ 0.6	$ -	$ -	$ -	$ 236.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 36.7	$ 199.5	$ 0.6	$ -	$ -	$ -	$ 236.8
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	200,059.9	809.9	-	4,066.7	3,238.4	32,383.4	250,887.1	206,869.7	169,844.7	31,411.8	110,801.0	212,051.5	1,222,424.0
Contract Energy (MWh)	30,054.1	23,193.1	25,715.8	27,086.1	30,806.6	63,919.2	67,636.3	61,277.4	22,010.0	31,184.2	29,743.0	36,917.3	449,543.2
Total Energy Excl. CSPP (MWh)	230,113.9	24,003.0	25,715.8	31,152.9	34,045.0	96,302.6	318,523.4	268,147.2	191,854.7	62,596.0	140,544.0	248,968.8	1,671,967.2
Market Cost ($ x 1000)	$ 9,944.3	$ 23.8	$ -	$ 144.0	$ 102.8	$ 917.8	$ 10,939.7	$ 8,931.4	$ 6,864.7	$ 1,313.6	$ 5,317.2	$ 11,568.0	$ 56,067.4
Contract Cost ($ x 1000)	$ 1,548.9	$ 1,200.7	$ 981.9	$ 1,034.6	$ 1,175.1	$ 3,068.4	$ 3,586.8	$ 3,225.3	$ 1,149.7	$ 1,618.4	$ 1,853.4	$ 2,293.6	$ 22,736.9
Total Cost Excl. CSPP ($ x 1000)	$ 11,493.2	$ 1,224.5	$ 981.9	$ 1,178.5	$ 1,277.9	$ 3,986.1	$ 14,526.6	$ 12,156.7	$ 8,014.4	$ 2,932.0	$ 7,170.7	$ 13,861.6	$ 78,804.2
Surplus Sales													
Energy (MWh)	72.3	92,290.3	182,641.3	146,281.1	266,106.4	181,275.7	8,137.6	15,383.9	56,086.2	106,370.7	51,795.9	7,691.6	1,114,133.0
Revenue Including Transmission Costs ($ x 1000)	$ 2.2	$ 3,158.0	$ 5,423.7	$ 4,279.8	$ 7,073.7	$ 5,175.6	$ 208.1	$ 401.8	$ 1,402.4	$ 2,945.8	$ 1,477.9	$ 248.1	$ 31,797.1
Transmission Costs ($ x 1000)	$ 0.1	$ 92.3	$ 182.6	$ 146.3	$ 266.1	$ 181.3	$ 8.1	$ 15.4	$ 56.1	$ 106.4	$ 51.8	$ 7.7	$ 1,114.1
Revenue Excluding Transmission Costs ($ x 1000)	$ 2.1	$ 3,065.7	$ 5,241.1	$ 4,133.5	$ 6,807.6	$ 4,994.3	$ 200.0	$ 386.4	$ 1,346.3	$ 2,839.4	$ 1,426.1	$ 240.4	$ 30,683.0
Net Power Supply Expense ($ x 1000)	$ 25,618.8	$ 10,822.0	$ 9,442.1	$ 8,266.0	$ 4,719.9	$ 10,613.7	$ 29,271.9	$ 26,758.9	$ 20,369.5	$ 14,278.5	$ 19,493.5	$ 27,850.8	$ 207,505.7

Idaho Power/602
Witness: Scott L. Wright

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Scott L. Wright
Power Supply Costs for April 1, 2009, through March 31, 2010

July 31, 2009

IPCO POWER SUPPLY COSTS FOR APRIL 1, 2009 -- MARCH 31, 2010 (Mulitple Gas Prices/80 Years of Hydro)
Repriced Using UE195 Settlement Methodology - October Update
AVERAGE

	April	May	June	July	August	September	October	November	December	January	February	March	Annual
Hydroelectric Generation (MWh)	864,268.9	866,449.0	842,395.2	727,873.1	688,036.5	555,471.4	527,759.4	478,321.1	695,521.7	743,548.7	858,155.2	870,114.3	8,717,914.4
Bridger													
Energy (MWh)	330,372.1	330,372.1	429,803.8	455,179.3	455,179.3	440,496.2	455,179.3	440,496.2	455,179.3	455,179.3	411,129.7	422,142.1	5,080,708.9
Cost ($ x 1000)	$ 5,133.8	$ 5,133.8	$ 6,679.0	$ 7,073.3	$ 7,073.3	$ 6,845.1	$ 7,073.3	$ 6,845.1	$ 7,073.3	$ 7,601.5	$ 6,865.8	$ 7,049.8	$ 80,447.1
Boardman													
Energy (MWh)	30,791.4	6,410.6	28,422.9	40,365.2	41,031.4	39,532.0	40,965.7	39,726.2	41,067.7	38,748.7	34,978.2	39,163.3	421,203.3
Cost ($ x 1000)	$ 496.8	$ 105.3	$ 471.2	$ 647.2	$ 656.5	$ 632.9	$ 655.6	$ 635.6	$ 657.0	$ 671.7	$ 606.7	$ 678.0	$ 6,914.5
Valmy													
Energy (MWh)	88,830.8	157,350.2	151,362.6	172,657.9	173,151.8	166,575.0	172,391.7	168,288.3	174,160.1	167,583.7	150,037.1	166,302.1	1,908,691.2
Cost ($ x 1000)	$ 2,171.1	$ 3,844.3	$ 3,712.0	$ 4,206.1	$ 4,217.3	$ 4,058.7	$ 4,200.0	$ 4,097.8	$ 4,240.4	$ 4,639.1	$ 4,155.9	$ 4,605.9	$ 48,148.6
Danskin													
Energy (MWh)	64.4	1.0	371.4	18,418.2	9,753.4	1,199.8	613.2	4,822.8	2,289.7	1,199.1	420.0	62.6	39,215.7
Cost ($ x 1000)	$ 6.2	$ 0.1	$ 33.4	$ 1,507.8	$ 794.9	$ 111.1	$ 52.4	$ 428.3	$ 216.0	$ 132.9	$ 47.3	$ 6.6	$ 3,336.8
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 315.5	$ 296.9	$ 315.5	$ 306.2	$ 315.5	$ 306.2	$ 315.5	$ 315.5	$ 306.2	$ 315.5	$ 306.2	$ 315.5	$ 3,730.3
Total Cost	$ 321.7	$ 297.0	$ 348.9	$ 1,814.0	$ 1,110.4	$ 417.3	$ 367.9	$ 743.8	$ 522.2	$ 448.4	$ 353.5	$ 322.1	$ 7,067.1
Bennett Mountain													
Energy (MWh)	2.4	-	10.4	7,658.1	3,726.1	59.9	14.4	404.8	134.1	70.2	23.8	0.6	12,104.9
Cost ($ x 1000)	$ 0.2	$ -	$ 1.0	$ 658.1	$ 313.7	$ 5.9	$ 1.4	$ 38.0	$ 13.2	$ 8.2	$ 2.8	$ 0.1	$ 1,042.7
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ 0.2	$ -	$ 1.0	$ 658.1	$ 313.7	$ 5.9	$ 1.4	$ 38.0	$ 13.2	$ 8.2	$ 2.8	$ 0.1	$ 1,042.7
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	4,048.0	11,051.7	70,244.5	187,228.9	104,442.2	67,262.7	8,781.5	65,667.7	93,483.4	93,575.4	4,424.8	1,388.2	711,599.0
Contract Energy (MWh)	34,356.0	31,709.3	69,427.5	72,599.6	67,511.3	30,031.7	35,463.5	32,718.0	42,172.0	34,868.2	31,284.2	35,271.0	517,412.2
Total Energy Excl. CSPP (MWh)	38,404.0	42,761.0	139,672.0	259,828.5	171,953.5	97,294.3	44,245.0	98,385.7	135,655.4	128,443.6	35,709.0	36,659.1	1,229,011.2
Market Cost ($ x 1000)	$ 225.3	$ 526.8	$ 3,225.8	$ 13,360.3	$ 8,932.5	$ 5,504.1	$ 669.6	$ 5,204.6	$ 7,915.6	$ 7,577.8	$ 357.3	$ 99.4	$ 53,599.3
Contract Cost ($ x 1000)	$ 1,285.0	$ 1,190.0	$ 3,317.7	$ 3,854.4	$ 3,573.4	$ 1,534.4	$ 1,804.6	$ 2,000.7	$ 2,563.6	$ 1,786.3	$ 1,603.1	$ 1,327.6	$ 25,841.0
Total Cost Excl. CSPP ($ x 1000)	$ 1,510.2	$ 1,716.8	$ 6,543.6	$ 17,214.7	$ 12,506.0	$ 7,038.5	$ 2,474.3	$ 7,205.4	$ 10,479.2	$ 9,364.2	$ 1,960.4	$ 1,427.0	$ 79,440.3
Surplus Sales													
Energy (MWh)	355,681.0	271,256.5	206,160.4	20,049.8	14,772.6	75,161.1	150,111.6	56,220.7	72,282.3	123,788.2	326,344.6	396,926.6	2,068,755.4
Revenue Including Transmission Costs ($ x 1000)	$ 17,947.4	$ 11,722.9	$ 8,583.6	$ 1,297.2	$ 1,145.6	$ 5,576.9	$ 10,380.9	$ 4,041.0	$ 5,550.7	$ 9,090.7	$ 23,900.3	$ 25,776.5	$ 125,013.7
Transmission Costs ($ x 1000)	$ 355.7	$ 271.3	$ 206.2	$ 20.0	$ 14.8	$ 75.2	$ 150.1	$ 56.2	$ 72.3	$ 123.8	$ 326.3	$ 396.9	$ 2,068.8
Revenue Excluding Transmission Costs ($ x 1000)	$ 17,591.7	$ 11,451.6	$ 8,377.5	$ 1,277.2	$ 1,130.9	$ 5,501.7	$ 10,230.8	$ 3,984.8	$ 5,478.4	$ 8,966.9	$ 23,574.0	$ 25,379.5	$ 122,944.9
Net Hedges													
Energy (MWh)													
Cost($ X 1000)													
Net Power Supply Costs ($ x 1000)	$ (7,957.7)	$ (354.4)	$ 9,378.1	$ 30,336.2	$ 24,746.3	$ 13,496.7	$ 4,541.5	$ 15,580.9	$ 17,506.9	$ 13,766.2	$ (9,628.8)	$ (11,296.8)	**$ 100,115.3**
PURPA ($ x 1000)	$ 3,760.1	$ 3,825.6	$ 3,418.3	$ 4,221.4	$ 5,290.1	$ 7,664.0	$ 8,119.4	$ 7,927.9	$ 6,414.2	$ 4,616.4	$ 4,064.0	$ 4,337.5	$ 63,659.0
Total Net Power Supply Expense ($ x 1000)	$ (4,197.6)	$ 3,471.2	$ 12,796.5	$ 34,557.6	$ 30,036.5	$ 21,160.7	$ 12,661.0	$ 23,508.7	$ 23,921.2	$ 18,382.6	$ (5,564.7)	$ (6,959.3)	**$ 163,774.3**
Sales at Customer Level (In 000s MWH)	1,023.002	1,059.790	1,234.928	1,447.472	1,514.781	1,410.612	1,159.171	1,103.558	1,242.955	1,344.423	1,275.857	1,150.879	14,967.426
Hours in Month	720	744	720	744	744	720	744	720	744	744	672	744	8760
Unit Cost / MWH (for PCAM)	($4.10)	$3.28	$10.36	$23.87	$19.83	$15.00	$10.92	$21.30	$19.25	$13.67	($4.36)	($6.05)	**$10.94**
Prices Used in Purchased Power & Surplus Sales Above:													
Heavy Load													
Portion of Purchased Power considered HL Purchases	**64.25%**	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	
Purchased Power HL Price	60.74	54.42	52.16	79.70	93.67	89.84	80.34	82.84	88.21	86.04	83.08	74.12	
Portion of Surplus Sales considered HL Surplus Sales	**62.70%**	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	
Surplus Sales HL Price	56.35	50.49	48.39	73.95	86.91	83.36	74.54	76.86	81.84	79.83	77.09	68.77	
Light Load													
Portion of Purchased Power considered LL Purchases	**35.75%**	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	
Purchased Power LL Price	46.50	35.54	34.72	56.36	70.89	67.43	68.91	72.82	78.32	71.89	76.56	67.08	
Portion of Surplus Sales considered LL Surplus Sales	**37.30%**	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	
Surplus Sales LL Price	40.55	30.99	30.27	49.15	61.82	58.80	60.10	63.51	68.30	62.70	66.76	58.50	

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE _______

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE IN THE STATE OF OREGON.	)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

JEANNETTE BOWMAN

July 31, 2009

Q. Please state your name and business address.

A. My name is Jeannette Bowman. 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 "Company") as a Senior Pricing Analyst.

Q. Please describe your educational background and work experience.

A. In 1973, I graduated from the College of Idaho earning a Bachelor of Arts degree in Social Studies and Mathematics. I have also done graduate work at Boise State University. In addition, I have attended electric utility ratemaking courses offered through New Mexico State University's Center for Public Utilities as well as various advanced rate courses presented by the Edison Electric Institute. From 1973 to 1981, I taught secondary school mathematics and social studies courses. In 1981, I joined Accounting Systems in Boise where my duties primarily involved implementing accounting software systems. In August 1982, I accepted a position at Idaho Power as a Rate Analyst. In July 1986, I was promoted to Senior Rate Analyst, now designated as Senior Pricing Analyst. My duties as a Senior Pricing Analyst include gathering, analyzing, and coordinating data from various departments throughout the Company required for development of jurisdictional separation studies, class cost-of-service studies, and rate design as well as other analyses as may be required. In addition, I have assisted in the development of the Company's tariffs.

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

A. I am sponsoring testimony in this proceeding to quantify the Oregon Jurisdictional Revenue Requirement resulting from the Jurisdictional Separation Study ("JSS"). My testimony will summarize the adjustments to the total system test year data used by the Company for purposes of restating the Company's rate base, revenues, and expenses for the twelve months ending December 31, 2009.

Q. Have you prepared exhibits for this proceeding?

A. Yes. I am offering the following exhibits:

1. Exhibit No. 701, Summary of Total Rate Base and Net Income Adjustments;
2. Exhibit No. 702, Summary of Adjustments – Electric Plant in Service;
3. Exhibit No. 703, Summary of Adjustments – Accumulated Provision for Depreciation & Amortization;
4. Exhibit No. 704, Summary of Adjustments – Additions & Deletions to Rate Base;
5. Exhibit No. 705, Summary of Adjustments – Operating Revenues;
6. Exhibit No. 706, Summary of Adjustments – Operation & Maintenance Expenses;
7. Exhibit No. 707, Summary of Adjustments – Depreciation & Amortization Expense;
8. Exhibit No. 708, Summary of Adjustments – Taxes Other than Income Taxes;
9. Exhibit No. 709, Summary of Adjustments – Regulatory Debits and Credits;
10. Exhibit No. 710, Summary of Adjustments – Income Taxes; and
11. Exhibit No. 711, Jurisdictional Separation Study – Oregon Revenue Requirement.

Q. Could you briefly summarize how the Company developed its 2009 Test Year in Exhibits Nos. 701-710?

A. Yes. The development of the 2009 Test Year ("2009 Test Year" or "Test Year") begins with 2008 actual financial data ("2008 Actuals"). 2008 Actuals were adjusted for traditional ratemaking adjustments to arrive at 2008 adjusted actual financial information

("2008 Base"). The development of the 2008 Base from 2008 Actuals was addressed in the testimony of Company witness Douglas Jones.

The 2008 Base was then adjusted to reach 2009 forecasted financial levels ("2009 Unadjusted Forecast Year"). Finally, traditional and other ratemaking adjustments were made to the 2009 Unadjusted Forecast Year to reach the Company's 2009 Test Year. Unless otherwise noted, the development of the values from 2008 Base to 2009 Test Year were addressed in the testimony of Company witness Catherine Miller.

Q. Please describe Exhibit No. 701.

A. Exhibit No. 701 consists of two pages and is a summary of the development of the adjusted total electric system rate base and the development of net income for the 2009 Test Year (twelve months ending December 31, 2009.)

The first set of data, displayed in column 3 of Exhibit No. 701, are the unadjusted 2008 historical, actual results of operations provided by Mr. Jones. The adjustments proposed by the Company for purposes of developing the 2009 adjusted total electric system combined rate base and net income are shown in columns 4 through 14 with the total system adjusted test year rate base, expenses, and revenues summarized in column 15. The columns are as follows:

(1) Column 4, titled: "2008 Adjustments" was provided by Mr. Jones and is detailed in his testimony. It reflects standard regulatory adjustments that should be applied to the 2008 actual results prior to applying methods to adjust to 2009 levels;

(2) Column 5, titled: "2008 Base" is the adjusted base to which the methods to create the 2009 Test Year were applied;

(3) Columns 6-10, titled: "2008 to 2009 Forecast Adjustments," and subtitled: "3-Yr," "O&M," "Fixed," and "Other," contain the various methods from the Forecast Methodology Manual sponsored by Ms. Miller, and detailed in her testimony, that were used

to adjust from the 2008 Base to a 2009 Unadjusted Forecast Year. Column 11 includes the resulting dataset once the various methods were applied;

(4) Columns 12 through 14 provide the development of the 2009 Test Year, starting with the "2009 Unadjusted Forecast Year" as found in Column 11;

(a) Column 12 includes standard normalizing adjustments that reflect the influence of weather, water, and market prices, such as the normalized net power supply expenses provided by Company witness Scott Wright;

(b) Column 13 includes standard annualizing adjustments, to reflect changes that occur within the Test Year, but need to be incorporated for the full year on an ongoing basis; and

(c) Column 14 includes known and measurable adjustments that will occur in 2010;

(5) Column 15 is the resulting dataset for the 2009 Test Year (twelve months ending December 31, 2009).

Page 2 of Exhibit No. 701 summarizes the development of rate base components for the twelve months ending December 31, 2009. The total combined rate base, based on actual, unadjusted 2008 results was $2,226,397,818 (column 3, line 62). After adjustment, the total combined rate base increases to $2,347,007,562 (column 15, line 62).

Page 2 of Exhibit No. 701 also includes the development of the total system net income for the twelve months ending December 31, 2009. Operating revenues are summarized on line 68. Total operating expenses are summarized on line 79.

Q. Please explain what types of adjustments were made for the development of the Oregon jurisdictional revenue requirement.

A. Five types of adjustments were made for the development of the Oregon jurisdictional revenue requirement.

First, normalizing adjustments were made to those items that are highly influenced by weather, water, and market prices. Mr. Wright discusses the normalization of the Company's net power supply expenses in his testimony. In addition, retail sales revenues and other items are normalized to reflect the impact of weather on sales. All these adjustments are included in columns 4 and 12 of Exhibit No. 701.

Second, adjustments to derive a 2009 Test Year, based on 2008 data, were described by Ms. Miller in her testimony. These adjustments are presented in columns 6 through 10 of Exhibit No. 701.

Third, annualizing adjustments were made to reflect changes that occur within the Test Year, but need to be incorporated for the full year on an ongoing basis. For example, the investment in major plant projects during the Test Year have been identified and incorporated into this rate case filing and treated as if they had been in place for the entire year. Correspondingly, depreciation expenses are annualized to reflect depreciation on those new assets as though they had been on the Company's books for the entire year. All annualizing adjustments are included in column 13.

Fourth, known and measurable adjustments are those changes that will occur in 2010 but are still appropriate to be incorporated for building the 2009 Test Year. These adjustments are included in column 14.

Fifth, other types of adjustments, such as those resulting from past Commission Orders, were used in developing the Test Year. For example, this Commission allows the inclusion of working cash in rate base at 4 percent of total operation and maintenance expense. Therefore, as incorporated in the Company's last general rate case proceeding, Docket No. UE 167 ("UE 167"), for every adjustment to the Company's operation and maintenance expense, there is a corresponding 4 percent adjustment to working cash. All these adjustments are included in columns 4 through 14 of Exhibit No. 701.

Q. Earlier in your testimony, you indicated system combined rate base components increased by $120,609,744 from $2,226,397,818 (2008 Actual) to $2,347,007,562 (2009 Test Year). Please begin by discussing the "2008 Adjustments" made to the rate base components shown in Exhibit No. 701.

A. The "2008 Adjustments" of negative $14,780,573 made to rate base components in Exhibit No. 701, page 1, column 4 include: (1) an increase of $320,183 to accumulated deferred income taxes to reflect the impact of the FERC credit for other federal agencies ("OFA") administrative charges and incremental security issues, (2) a reduction of $9,865,355 to remove the pre-paid items not traditionally included in a test year's rate base, (3) a reduction of $3,727,791 to the authorized working cash allowance, per Public Utility Commission of Oregon ("OPUC") methodology, to reflect 4 percent of 2008 actual operation and maintenance ("O&M") expense adjustments, (4) a reduction of $1,340,655 to remove all but $4,977,507 of plant held for future use, (5) a reduction of $81,423 to reflect the unamortized portion of the Electric Plant Acquisition Adjustment associated with the Prairie Power Rural Electric Cooperative purchase in July 1992, and (6) a regulatory decrease of $85,531 of investment in the Idaho Energy Resources Company ("IERCo"). These adjustments were provided by Mr. Jones and the Company's Tax Department.

Q. Please continue the explanation of adjustments to combined rate base components by discussing "2008 to 2009 Forecast Adjustments" summarized in Exhibit No. 701, page 1, columns 6-10.

A. The only O&M combined rate base component adjustment in Exhibit No. 701, page 1, column 7 is an increase of $117,981 to the authorized working cash allowance, per OPUC methodology, to reflect 4 percent of O&M adjustments within O&M.

The "Fixed" combined rate base adjustments of positive $142,690,545 in Exhibit No. 701, page 1, column 9 include: (1) an increase of $193,511,911 in plant-in-service, (2) a decrease of $59,370,545 because of an increase in accumulated depreciation, (3) an increase of $449,091 because of a decrease in accumulated amortization, (4) an increase of $7,421,498 because of a decrease in customer advances for construction, (5) an increase of $62,628 to the authorized working cash allowance, per OPUC methodology, to reflect 4 percent of “Fixed” adjustments within O&M expenses, (6) a decrease of $3,242,604 in Idaho deferred conservation programs, (7) a decrease of $205,772 in other regulatory deferred programs, and (8) an increase of $4,064,338 to the IERCo rate base. The methods for quantifying adjustments are described in detail in Ms. Miller’s testimony.

The “Other” combined rate base adjustments of negative $22,860,090 in Exhibit No. 701, page 1, column 10 include: (1) a decrease of $22,872,289 in accumulated deferred income taxes provided by the Company’s Tax Department and (2) an increase of $12,199 to the authorized working cash allowance, per OPUC methodology, to reflect 4 percent of “Other” adjustments within O&M expenses.

Q. Please discuss the normalizing adjustments to the combined rate base components summarized in Exhibit No. 701, page 1, column 12.

A. The “Normalizing Adjustments” of negative $2,363,686 made to combined rate base components in Exhibit No. 701, page 1, column 12 include: (1) a decrease of $2,889,043 to fuel inventory, as provided by Mr. Wright, to reflect normalized operating criteria to required coal inventories at Bridger, Valmy, and Boardman and (2) an increase of $525,357 to the authorized working cash allowance to reflect 4 percent of “Normalizing Adjustments” within O&M expenses, per OPUC methodology.

Q. Please discuss the annualizing adjustments to the combined rate base components summarized in Exhibit No. 701, page 1, column 13.

A. The “Annualizing Adjustments” of positive $17,654,843 made to combined rate base components in Exhibit No. 701, page 1, column 13 include several items. First of all, an adjustment of $5,946,801 was made to represent a full year of costs for production plant investment made during the Test Year. Major plant projects which are greater than

$2.0 million and expected to be on-line and serving customers before the end of 2009 were treated as if they had been in place for the entire year. This adjustment is shown on line 48. Similar annualizing adjustments were made for transmission projects (positive $4,880,227 as shown on line 49), for distribution (positive $6,688,950 as shown on line 50), and for general plant projects (positive $1,052,616 as shown on line 51). The total annualizing adjustment for the 2009 major plant investment is $18,568,594, as shown on line 52.

An adjustment of negative $1,307,272 was made to accumulated provision for depreciation to capture the rate base impact of the annualized adjustment to depreciation expense.

Likewise, an adjustment of positive $2,052 was made to accumulated provision for amortization to capture the rate base impact of the annualized adjustment to amortization expense.

Lastly, an adjustment of positive $395,573 was made to the authorized working cash allowance, per OPUC methodology, to reflect 4 percent of "Annualizing Adjustments" to O&M expenses.

Q. Please discuss the known and measurable ("K&M") adjustments to the rate base components summarized in Exhibit No. 701, page 1, column 14.

A. The "Known & Measurable Adjustments" of positive $150,723 made to combined rate base components in Exhibit No. 701, page 1, column 14 includes $2,442 of interest on Commission-allowed deferral for the Oregon portion of the Grid West loan. Also, an adjustment of positive $148,281 was made to the authorized working cash allowance, per OPUC methodology, to reflect 4 percent of K&M adjustments within O&M expenses.

Q. Have you included any other adjustments to the combined rate base?

A. No.

Q. Please describe the Company's adjustments to the operating income components for the twelve months ending December 31, 2009, shown in page 2, lines

65-69 of Exhibit No. 701.

A. The "2008 Adjustments" of negative $104,682,635 summarized in column 4, lines 65-69 of Exhibit No. 701 include: (1) a decrease of $92,160,402 to normalize retail sales revenue by removing the impact of weather, (2) a decrease of $448,032 to normalize firm sales for resale revenues by removing the impact of weather, (3) a decrease of $4,679,193 to system opportunity sales revenue to reflect the decreased level of opportunity sales associated with the multiple historical water conditions, (4) an increase of $1,505,432 to add regulatory-recognized merchandising revenue (Account 415), (5) an increase of $9,979,836 to remove the Open Access Transmission Tariff ("OATT") tariff refund, and (6) a decrease of $18,880,276 to remove the Idaho energy efficiency rider (equal offset adjustment to O&M Account 908). These adjustments were provided by Mr. Wright and Mr. Jones.

"2008 to 2009 Forecast Adjustments" to revenue of negative $6,759,582 summarized in Exhibit No. 701, columns 6-10, lines 65-68 include: (1) a decrease of $658,334 in regulatory-recognized merchandising revenues (Account 415), (2) a decrease of $420,226 in other operating revenue (Accounts 451-454), and (3) an decrease of $5,681,022 in other electric revenues (Account 456).

The "Normalizing Adjustments" of positive $58,580,525 summarized in Exhibit No. 701, column 12, lines 65-68, include: (1) an increase of $49,838,391 to normalize 2009 retail sales revenue, (2) an increase of $59,634 to normalize 2009 firm sales for resale revenues, and (3) an increase of $8,682,500 to system opportunity sales revenue to reflect the settlement value included in Docket No. UE 195.

Normalized energy sales are provided by the Company's Load Forecasting Department for each rate class. Using these figures, normalized usage blocks are estimated based on proportions of actual recorded usage from the historic year. Once the normalized blocks have been derived, all billing components are multiplied by current base rates to develop normalized retail sales revenue and firm sales for resale revenue.

Normalized opportunity sales revenue is provided by Mr. Wright.

Q. Please describe the Company's adjustments to the operating expense components shown in page 2, lines 69-79 of Exhibit No. 701. Please begin with a description of O&M expense adjustments.

A. "2008 Adjustments" of negative $93,194,785 to O&M expenses summarized in column 4, line 70 of Exhibit No. 701 include: (1) a decrease of $59,541,193 to reflect a normalized net decrease in fuel and purchase power expense associated with multiple historical water conditions, an increase in Qualifying Facilities ("QF" under PURPA contract) expense, as well as the exclusion of all PCA/EPC-related expenses, (2) a decrease of $18,880,276 to remove the impact of the Idaho energy efficiency rider (corresponding adjustment in operating revenues), (3) a decrease of $15,448,509 to salary incentive payments, (4) a decrease of $8,636 of management expenses, (5) a decrease of $44,969 of intervenor funding expenses, (6) a decrease of $236,828 of standard regulatory exclusion of General Advertising, Account 930.1, (7) a decrease of $215,468 to exclude various memberships and contributions expenses, (8) a decrease of $22,789 to exclude various purchasing card ("P-Card") expenses, and (9) an increase of $1,203,883 to add regulatory-recognized merchandising expenses (Account 416). The Net Power Supply adjustments were provided by Mr. Wright. All other adjustments were provided by Mr. Jones.

"2008 to 2009 Forecast Adjustments" to O&M expenses of positive $4,820,197 found in Exhibit No. 701, columns 6-10, are discussed in detail in the testimony of Ms. Miller.

"Normalizing Adjustments" to O&M expenses of positive $13,133,930 found in Exhibit No. 701, column 12 include 2009 adjustments to Power Supply costs as detailed in the testimony of Mr. Wright.

"Annualizing Adjustments" to O&M expenses of positive $9,889,330 found in Exhibit No. 701, column 13 are 2009 adjustments which include: (1) an increase of $3,104,828 to operating payroll, (2) an increase of $6,776,573 to normalized salary incentives, and (3) an increase of $7,929 for insurance of major plant additions.

"K&M Adjustments" to O&M expenses of positive $3,707,033 found in Exhibit No. 701, column 14 are adjustments which include: (1) an increase of $3,692,594 for a 2010 salary structure adjustment and (2) a Commission-allowed increase of $14,439 for the amortization of the Oregon portion of the Grid West loan.

Q. Please describe the Company's adjustments to the depreciation expense components shown in page 2, line 71 of Exhibit No. 701.

A. The "Fixed" adjustments of positive $2,375,647 to depreciation expense in column 9 of Schedule 36 are explained in detail in Ms. Miller's testimony.

The "Annualizing Adjustment" of positive $2,588,340 in column 13 reflects the additional depreciation expense related to major 2009 plant additions.

Q. Please describe the Company's adjustments to the amortization expense components shown in page 2, line 72 of Exhibit No. 701.

A. The "2008 Adjustments" of positive $504,115 in column 4 reflects the removal on non-regulatory Account 411.8, Gains from Disposition of Allowances as provided by Mr. Jones.

The "Fixed" adjustment increase of $803,109 in column 9 are explained in detail in Ms. Miller's testimony.

The "Annualizing Adjustment" of positive $4,104 in column 13 reflects the additional amortization expense related to major 2009 plant additions as provided by Ms. Miller.

Q. Please describe the Company's adjustments to taxes other than income taxes shown in page 2, line 73 of Exhibit No. 701.

A. The "3-Yr" and "Fixed" adjustments in columns 6 and 9 illustrate total increases of $1,080,610 and are explained in detail in Ms. Miller's testimony.

A "Normalizing Adjustment" of positive $488,490 in column 12 was made to reflect the 2009 kilowatt-hour ("kWh") tax based on normalized power supply. This adjustment was provided by the Company's Tax Department.

The "Annualizing Adjustment" of positive $72,575 reflects annualized property taxes for 2009 major plant additions.

Q. Please describe the Company's adjustments to regulatory debits and credits shown in page 2, line 74 of Exhibit No. 701.

A. The only adjustment to regulatory debits and credits was under "2008 Adjustments" in column 4. The positive $3,781,013 adjustment removes the Idaho Fixed Cost Adjustment in Account 407.4.

Q. Were there any other adjustments made to the operating expenses of the Company?

A. Yes. All of the adjustments in tax-related line items in Exhibit No. 701, page 2, lines 75-78 were provided by the Company's Tax Department.

Q. Please describe Exhibit No. 702.

A. Exhibit No. 702 consists of two pages and provides detail of the adjustments, by FERC account, to the Company's electric plant in service used in this proceeding.

Q. Please describe Exhibit No. 703.

A. Exhibit No. 703 consists of two pages and provides details of the accumulated provision for depreciation and amortization reserve.

Q. Please describe Exhibit No. 704.

A. Exhibit No. 704 consists of two pages and provides details of other additions to or deductions from the Company's total combined rate base.

Q. Please describe Exhibit No. 705.

A. Exhibit No. 705 is a one-page summary, by FERC account, of the Company's operating revenues for the Test Year used in this proceeding.

Q. Please describe Exhibit No. 706.

A. Exhibit No. 706 consists of six pages detailing unadjusted and adjusted Test Year operation and maintenance expenses for the twelve months ending December 31, 2009.

Q. Please describe Exhibit No. 707.

A. Exhibit No. 707 consists of two pages and provides greater detailed information by FERC account of depreciation and amortization expenses used in this proceeding.

Q. Please describe Exhibit No. 708.

A. Exhibit No. 708 is a one-page exhibit detailing taxes other than income taxes used in this proceeding.

Q. Please describe Exhibit No. 709.

A. Exhibit No. 709 is a one-page exhibit detailing regulatory debits and credits.

Q. Please describe Exhibit No. 710.

A. Exhibit No. 710 consists of four pages detailing the income tax-related adjustments that result in the adjusted tax expenses. The Company's Tax Department provided these adjustments.

Q. Have you prepared an exhibit that sets forth the Oregon jurisdictional revenue deficiency?

A. Yes. I have prepared Exhibit No. 711 titled "Jurisdictional Revenue Requirement" consisting of 36 pages.

Q. Please describe Exhibit No. 711.

A. Exhibit No. 711 is the complete Jurisdictional Revenue Requirement report detailing the allocation of each component of rate base, operating revenues, and expenses by FERC account resulting in the Oregon jurisdictional revenue deficiency. The Jurisdictional Separation Study ("JSS") is organized as follows:

- Summary of Results
- Table 1 – Electric Plant in Service;
- Table 2 – Accumulated Provision for Depreciation (and Amortization);
- Table 3 – Additions & Deletions to Rate Base;
- Table 4 – Operating Revenues;
- Table 5 – Operation & Maintenance Expenses;
- Table 6 – Depreciation & Amortization Expense;
- Table 7 – Taxes Other Than Income Taxes;
- Table 8 – Regulatory Debits & Credits;
- Table 9 – Income Taxes;
- Table 10 – Calculation of Federal Income Tax;
- Table 11 – State Income Tax – Oregon;
- Table 12 – State Income Tax – Idaho and Other;
- Table 13 – Development of Labor Related Allocator;
- Table 14 – Allocation Factors;
- Table 15 – Distribution Jurisdictional Allocation; and
- Table 16 – Allocation Factors-Ratios.

Q. Please discuss the methodology used to jurisdictionally separate costs in the preparation of this study.

A. A three-step process was used to separate costs among jurisdictions. The three steps are classification, functionalization, and allocation of costs. In all three steps, recognition was given to the way in which costs are incurred by relating these costs to utility operations. The methodology used to separate costs by jurisdiction and calculate the Oregon jurisdictional revenue requirement in the present case is substantially the same methodology utilized in the Company's last general rate case, UE 167.

Q. Would you please briefly explain the meaning of classification, functionalization, and allocation?

A. Classification groups costs into three categories: (1) demand-related, (2) energy-related, and (3) customer-related. In addition to classification, costs are functionalized; that is, costs are identified with utility operating functions such as generation, transmission, and distribution. Individual plant items are examined and, where possible, the associated investment costs are assigned to one or more operating functions. Once the Company's total system costs are classified and assigned to the appropriate function, they may be allocated among jurisdictions.

The process of allocation is one of apportioning the total system cost among jurisdictions by introducing allocation factors into the process. An allocation factor is an array of numbers which specifies the jurisdictional value as a share or percent of the total system quantity. For example, in the case of energy-related costs, the allocation factor is annual jurisdictional energy use, adjusted for losses, divided by the total system energy use.

Once individual accounts have been allocated to the various jurisdictions, it is possible to summarize these into total utility rate base and net income by jurisdiction. The results are stated in a summary form to measure adequacy of revenues for the jurisdiction under consideration. The measure of adequacy is typically the rate of return earned on rate base, which is compared to the requested rate of return.

Q. How have the various functional plant and cost items been allocated?

A. The average of the twelve monthly coincident peak demands was used to allocate the demand-related costs. This allocation method has been used by the Company for the past two decades in all of its filings requiring a jurisdictional separation study. This allocation method was adopted by this Commission and accepted by the Idaho Public Utilities Commission ("IPUC") and by the Federal Energy Regulatory Commission ("FERC"). The demand-related allocation factors used in the study are designated as D10, D11, D12, and D60. The respective values used in these demand allocation factors are shown at line numbers 991 through 995 of Exhibit No. 711.

Q. How were the energy-related expenses allocated among jurisdictions?

A. Energy-related expenses were allocated based on normalized jurisdictional kilowatt-hour sales and adjusted for losses to establish energy requirements at the generation level. The energy-related allocation factors used in the study are designated as E10 and E99. The respective values used in these energy allocation factors are shown on lines 997 through 999 of Exhibit No. 711.

Q. What was the method by which you allocated customer-related costs?

A. The principal customer-related expenses, which required allocation, were meter reading (FERC Account 902), customer accounting, and billing (FERC Account 903). These accounts were allocated based upon a review of actual Company practice of reading meters and preparing monthly bills or statements.

Q. What method was used to allocate certain labor-related administrative and general expenses?

A. In accordance with FERC approved procedures, administrative and general expenses were allocated in accordance with functionalized wages and salaries. These labor-related allocation factors are shown on lines 792 through 987 of Exhibit No. 711.

Q. Please describe the derivation of the 2009 total system allocation factors used in this case.

A. The allocation factors in the 2009 Jurisdictional Separation Study were based on either the 2008 year-end data or 2009 assumptions. The capacity or demand–related allocation factors (D10, D11, D12, and D60) were created using the 2008 demand ratios from the load research sample applied to the 2009 Test Year energy. The energy-related allocation factors were the 2009 Test Year load at generation level (E10) and at customer level (E99).

Q. Briefly describe the manner in which you allocated electric plant in service as shown in Table 1 of Exhibit No. 711.

A. Production plant was allocated to all jurisdictions based on the average of the twelve monthly coincident peaks. The allocation of transmission and distribution plant was based on the same methodology.

Q. Would you describe the functional categories used for allocation and direct assignment of transmission plant and distribution substations?

A. Transmission facilities are the facilities that form the bulk of the power transmission system together with transmission, step-up substation facilities required to introduce the Company's generation into the power supply system, and include facilities rated at 500 kilovolt ("kV") through 46 kV. Distribution facilities refer to lower voltage lines and the substation facilities that provide localized service. Some transmission and distribution facilities were directly assigned to the customers who paid for the exclusive use of those facilities.

Q. Please describe the manner in which you allocated general electric plant in service.

A. General plant was allocated on the same basis as the sum of the allocated investments in production, transmission, and distribution plant.

Q. How have you allocated the accumulated provision for depreciation and amortization of other utility plant?

A. Accumulated provision for depreciation was allocated among jurisdictions as shown on Table 2 of Exhibit No. 711. The accumulated totals for each type of production plant and for each primary plant account in other functional groups were allocated based on the related plant account as allocated in Table 1. Amortization of other utility plant was functionalized and then allocated based on the related plant items as allocated in Table 1.

Q. Please describe Table 3 of Exhibit No. 711.

A. Table 3 details the allocation of all other additions to or deductions from rate base. Deductions from rate base include customer advances for construction that were directly assigned to the customers by jurisdiction, and the accumulated deferred income taxes that were allocated by plant. Additions to rate base include: (1) materials and supplies that were functionalized and allocated by the respective plant allocators, (2) fuel inventory that was allocated on the basis of energy, (3) components of IERCo, the Company's fuel subsidiary, that were allocated based on energy, and (4) Commission-ordered deferred investment that was directly assigned to the Oregon jurisdiction.

All rate base items, with the exception of accumulated deferred income taxes and the investment in conservation programs, reflect the average of ending balances.

Q. Please describe Table 4 of Exhibit No. 711.

A. Table 4 contains the adjusted firm operating revenues for each jurisdiction for the Test Year (twelve months ending December 31, 2009). Opportunity sales are non-firm energy sales to other utilities, which were credited to each jurisdiction in proportion to generation-level energy use.

Other operating revenues were either allocated among jurisdictions in a manner that offset related allocations of rate base or, where a particular revenue item could be associated with a specific jurisdiction, directly assigned.

Q. Briefly describe the methods by which operation and maintenance expenses were allocated in Table 5.

A. The allocation of each operation and maintenance expense is detailed on Table 5 of Exhibit No. 711. In general, the basis for each allocation is identifiable with the source code listed on Exhibit No. 711. Demands are identified by a source code beginning with a "D" prefix, energy use is identified by a source code beginning with an "E" prefix, related plant is identified by a line number source code, and customer-weighted allocation factors begin with a "CW" prefix.

Q. In what manner are supervision and engineering expenses treated throughout the allocation of operation and maintenance expenses?

A. For the applicable expense account in each functional group, the labor component was separately allocated in accordance with the detail provided on Table 13 of Exhibit No. 711. The total of allocated labor in each functional group became the basis for the allocation of supervision and engineering expense. Total allocated labor expense served the additional purpose of allocating employee pension and other labor-related taxes and expenses. Table 13 of Exhibit No. 711 details the development of all the labor-related allocation factors used in this study.

Q. Please describe Table 6 of Exhibit No. 711.

A. The allocation of depreciation expense and amortization of limited term plant is set forth on Table 6. These expenses were identified by type of production plant or by primary plant account for other functional plant groups and allocated consistent with the related plant account.

Q. Please describe Table 7 of Exhibit No. 711 and the allocation of taxes other than income taxes.

A. Taxes other than income taxes were treated individually and allocated in a manner consistent with the bases by which the respective taxes are assessed.

Q. Please describe Table 8 of Exhibit No. 711.

A. Table 8 of Exhibit No. 711 details the amortization of regulatory debits and credits. No amounts were included in the 2009 test year.

Q. Please describe Table 9 of Exhibit No. 711.

A. The expenses shown on Table 9 consist of deferred income taxes and the investment tax credit adjustments which were functionalized and allocated based on net income before taxes. State and federal income tax liabilities are also summarized on Table

9. The income taxes shown on Tables 10 through 12 were obtained from the Company's Tax Department.

Q. Please describe how you allocated federal and state income taxes shown on Tables 10 through 12 of Exhibit No. 711.

A. The respective tax bases were developed, and taxes were calculated directly, for each jurisdiction. Operating income before taxes represents adjusted operating revenues less all adjusted operating expenses treated heretofore with the exception of deferred income taxes and investment tax credits. Adjusted interest expense was allocated by the combined rate base to develop net operating income before taxes. Subsequent additions to or deductions from the respective tax bases were allocated to each jurisdiction by net income before taxes. In this manner, taxable income for each jurisdiction was developed and the appropriate tax rate was applied. Final tax amounts result after the allocation of adjustments and tax credits. All details relating to the calculation of federal, Oregon, Idaho, and other state income taxes are found on Tables 10, 11, and 12.

Q. Please describe Tables 13 through 16 of Exhibit No. 711.

A. Tables 13 through 16 of Exhibit No. 711 list the principal allocation factors used in the study and the respective jurisdictional values for each allocation factor. Table 16 lists the ratios of the principal allocation factors included in Table 14.

Q. Please describe the development of the Oregon jurisdictional revenue deficiency.

A. The summary of results is presented on pages 1 and 2 of Exhibit No. 711. The development of the Oregon jurisdictional revenue deficiency is presented in the column entitled "Oregon Retail" on page 1 of Exhibit No. 711. The Oregon consolidated operating income of $5,152,315 (line 26) resulted in a return on rate base of 4.65 percent (line 27). Based upon the Company's request for an overall rate of return of 8.68 percent provided by Company witness Steven Keen, the Company's Oregon jurisdictional net income should be

$9,615,775, as shown on line 32. The resulting earnings deficiency is $4,463,460, as shown on line 33.

Q. What net-to-gross or incremental income tax factor did you use in developing the Oregon jurisdictional revenue deficiency?

A. The composite incremental tax multiplier of 1.642 is the assimilation of the federal effective tax rate, an Idaho composite tax rate, an Oregon composite tax rate, and an additional state composite tax rate. This value, as shown on line 37 of Exhibit No. 711, was provided by the Company's Tax Department.

Q. What is the resulting Oregon jurisdictional revenue deficiency?

A. The result of the Jurisdictional Separation Study, as shown on page 1, line 38 of Exhibit No. 711, indicates a total revenue deficiency of $7.3 million for the Oregon retail jurisdiction. This represents a required 22.6 percent increase in normalized Oregon jurisdictional revenues.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Jeannette Bowman
Summary of Total Rate Base and Net Income Adjustments

July 31, 2009

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2009

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
		2008	2008	2008	2008 to 2009 Forecast Adjustments					2009 Unadjusted	Normalizing	Annualizing	Known & Measurable	2009
	Description	Actuals	Adjustments	Base	3-Yr	O&M	Growth %	Fixed	Other	Forecast Year	Adjustments	Adjustments	Adjustments	Test Year
4	***SUMMARY OF RESULTS***													
5	**RATE OF RETURN UNDER PRESENT RATES**													
6	TOTAL COMBINED RATE BASE	2,226,397,818	(14,780,573)	2,211,617,245	0	117,981		142,690,545	(22,860,090)	2,331,565,681	(2,363,686)	17,654,843	150,723	2,347,007,562
7														
8	OPERATING REVENUES													
9	FIRM JURISDICTIONAL SALES	786,797,974	(92,608,434)	694,189,540	0	0		0	0	694,189,540	49,898,025	0	0	744,087,565
10	SYSTEM OPPORTUNITY SALES	118,941,593	(4,679,193)	114,262,400	0	0		0	0	114,262,400	8,682,500	0	0	122,944,900
11	OTHER OPERATING REVENUES	50,335,998	(7,395,008)	42,940,990	(420,226)	0		(6,339,356)	0	36,181,407	0	0	0	36,181,407
12	TOTAL OPERATING REVENUES	956,075,565	(104,682,635)	851,392,930	(420,226)	0		(6,339,356)	0	844,633,347	58,580,525	0	0	903,213,872
13	OPERATING EXPENSES													
14	OPERATION & MAINTENANCE EXPENSES	649,816,334	(93,194,785)	556,621,549	0	2,949,530		1,565,688	304,980	561,441,747	13,133,930	9,889,330	3,707,032	588,172,039
15	DEPRECIATION EXPENSE	96,637,583	0	96,637,583	0	0		2,375,647	0	99,013,231	0	2,588,340	0	101,601,570
16	AMORTIZATION OF LIMITED TERM PLANT	4,943,918	504,115	5,448,033	0	0		803,109	0	6,251,142	0	4,104	0	6,255,245
17	TAXES OTHER THAN INCOME	19,083,954	(0)	19,083,954	29,660	0		1,050,950	0	20,164,564	488,490	72,575	0	20,725,629
18	REGULATORY DEBITS/CREDITS	(3,781,013)	3,781,013	0	0	0		0	0	0	0	0	0	0
19	PROVISION FOR DEFERRED INCOME TAXES	40,319,488	0	40,319,488	0	0		0	(4,261,587)	36,057,901	0	0	0	36,057,901
20	INVESTMENT TAX CREDIT ADJUSTMENT	2,269,367	0	2,269,367	0	0		0	(3,226,936)	(957,569)	0	0	0	(957,569)
21	FEDERAL INCOME TAXES	(1,816,783)	(8,524,776)	(10,341,559)	(147,540)	(967,298)		(3,979,591)	8,803,339	(6,632,650)	14,744,010	(5,087,863)	(1,215,721)	1,807,776
22	STATE INCOME TAXES	(4,930,646)	(1,637,630)	(6,568,277)	(28,343)	(185,820)		(764,489)	3,986,231	(3,560,698)	2,832,361	(977,391)	(233,543)	(1,939,271)
23	TOTAL OPERATING EXPENSES	802,542,203	(99,072,064)	703,470,139	(146,223)	1,796,411		1,051,313	5,606,027	711,777,668	31,198,791	6,489,094	2,257,768	751,723,321
24	OPERATING INCOME	153,533,362	(5,610,570)	147,922,791	(274,003)	(1,796,411)		(7,390,669)	(5,606,027)	132,855,679	27,381,734	(6,489,094)	(2,257,768)	151,490,551
25	ADD: IERCO OPERATING INCOME	5,086,761	(337,988)	4,748,773	0	0		1,380,094	0	6,128,867	0	0	0	6,128,867
26	CONSOLIDATED OPERATING INCOME	158,620,123	(5,948,558)	152,671,564	(274,003)	(1,796,411)		(6,010,575)	(5,606,027)	138,984,546	27,381,734	(6,489,094)	(2,257,768)	157,619,418
27	RATE OF RETURN UNDER PRESENT RATES	7.12%		6.90%										6.72%
28														
29	**DEVELOPMENT OF REVENUE REQUIREMENTS**													
30	RATE OF RETURN @ 11.25% ROE	8.68%	8.68%	8.68%	8.68%	8.68%		8.68%	8.68%	8.68%	8.68%	8.68%	8.68%	8.68%
31														
32	RETURN	193,251,331	(1,282,954)	191,968,377	0	10,241		12,385,539	(1,984,256)	202,379,901	(205,168)	1,532,440	13,083	203,720,256
33	EARNINGS DEFICIENCY	34,631,208	4,665,605	39,296,813	274,003	1,806,652		18,396,115	3,621,772	63,395,355	(27,586,902)	8,021,534	2,270,851	46,100,838
34	ADD: CWIP (RELICENSING)	0	0	0	0	0		0	0	0	0	0	0	0
35	DEFICIENCY WITH CWIP	34,631,208	4,665,605	39,296,813	274,003	1,806,652		18,396,115	3,621,772	63,395,355	(27,586,902)	8,021,534	2,270,851	46,100,838
36														
37	NET-TO-GROSS TAX MULTIPLIER	1.642	1.642	1.642	1.642	1.642		1.642	1.642	1.642	1.642	1.642	1.642	1.642
38	**REVENUE DEFICIENCY**	56,864,443	7,660,923	64,525,366	449,913	2,966,523		30,206,420	5,946,949	104,095,173	(45,297,692)	13,171,359	3,728,737	75,697,577
39														0
40	FIRM JURISDICTIONAL REVENUES	792,209,612	(92,608,434)	699,601,178	0	0		(772,514)	0	698,828,664	49,898,025	0	0	748,726,689
41	PERCENT INCREASE REQUIRED	7.18%		9.22%						14.90%				10.11%
42														0
43	SALES AND WHEELING REVENUES REQUIRED	849,074,055	(84,947,511)	764,126,544	449,913	2,966,523		29,433,906	5,946,949	802,923,837	4,600,333	13,171,359	3,728,737	824,424,266

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2009

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
		2008	2008	2008	2008 to 2009 Forecast Adjustments					2009 Unadjusted	Normalizing	Annualizing	Known & Measurable	2009
	Description	Actuals	Adjustments	Base	3-Yr	O&M	Growth %	Fixed	Other	Forecast Year	Adjustments	Adjustments	Adjustments	Test Year
44	***SUMMARY OF RESULTS***													
45	**DEVELOPMENT OF RATE BASE COMPONENTS**													
46	ELECTRIC PLANT IN SERVICE													
47	INTANGIBLE PLANT	49,138,777	0	49,138,777	0	0	0	3,168,771	0	52,307,548	0	0	0	52,307,548
48	PRODUCTION PLANT	1,697,939,113	0	1,697,939,113	0	0	0	45,994,749	0	1,743,933,861	0	5,946,801	0	1,749,880,662
49	TRANSMISSION PLANT	706,385,420	0	706,385,420	0	0	0	51,292,481	0	757,677,901	0	4,880,227	0	762,558,128
50	DISTRIBUTION PLANT	1,208,183,947	0	1,208,183,947	0	0	0	76,699,612	0	1,284,883,560	0	6,688,950	0	1,291,572,510
51	GENERAL PLANT	239,296,089	0	239,296,089	0	0	0	16,356,298	0	255,652,387	0	1,052,616	0	256,705,003
52	TOTAL ELECTRIC PLANT IN SERVICE	3,900,943,345	0	3,900,943,345	0	0	0	193,511,911	0	4,094,455,256	0	18,568,594	0	4,113,023,850
53	LESS: ACCUM PROVISION FOR DEPRECIATION	1,617,442,989	0	1,617,442,989	0	0	0	59,370,545	0	1,676,813,534	0	1,307,272	0	1,678,120,806
54	AMORT OF OTHER UTILITY PLANT	17,908,337	0	17,908,337	0	0	0	(449,091)	0	17,459,246	0	2,052	0	17,461,298
55	NET ELECTRIC PLANT IN SERVICE	2,265,592,019	0	2,265,592,019	0	0	0	134,590,457	0	2,400,182,476	0	17,259,270	0	2,417,441,746
56	LESS: CUSTOMER ADV FOR CONSTRUCTION	31,785,562	0	31,785,562	0	0	0	(7,421,498)	0	24,364,064	0	0	0	24,364,064
57	LESS: ACCUM DEFERRED INCOME TAXES	208,487,757	(320,183)	208,167,574	0	0	0	0	22,872,289	231,039,863	0	0	0	231,039,863
58	ADD : PLT HLD FOR FUTURE+ACQUIS ADJ	6,318,163	(1,422,078)	4,896,084	0	0	0	0	0	4,896,084	0	0	0	4,896,084
59	ADD : WORKING CAPITAL	105,017,990	(13,593,147)	91,424,843	0	117,981	0	62,628	12,199	91,617,651	(2,363,686)	395,573	148,281	89,797,820
60	ADD : CONSERVATION+OTHER DFRD PROG.	6,380,601	0	6,380,601	0	0	0	(3,448,376)	0	2,932,225	0	0	2,442	2,934,667
61	ADD : SUBSIDIARY RATE BASE	83,362,365	(85,531)	83,276,834	0	0	0	4,064,338	0	87,341,172	0	0	0	87,341,172
62	TOTAL COMBINED RATE BASE	2,226,397,818	(14,780,573)	2,211,617,245	0	117,981	0	142,690,545	(22,860,090)	2,331,565,681	(2,363,686)	17,654,843	150,723	2,347,007,562
63														
64	**DEVELOPMENT OF NET INCOME COMPONENTS**													
65	OPERATING REVENUES													
66	SALES REVENUES	905,739,567	(97,287,627)	808,451,940	0	0	0	0	0	808,451,940	58,580,525	0	0	867,032,465
67	OTHER OPERATING REVENUES	50,335,998	(7,395,008)	42,940,990	(420,226)	0	0	(6,339,356)	0	36,181,407	0	0	0	36,181,407
68	TOTAL OPERATING REVENUES	956,075,565	(104,682,635)	851,392,930	(420,226)	0	0	(6,339,356)	0	844,633,347	58,580,525	0	0	903,213,872
69	OPERATING EXPENSES			0										
70	OPERATION & MAINTENANCE EXPENSES	649,816,334	(93,194,785)	556,621,549	0	2,949,530	0	1,565,688	304,980	561,441,747	13,133,930	9,889,330	3,707,032	588,172,039
71	DEPRECIATION EXPENSE	96,637,583	0	96,637,583	0	0	0	2,375,647	0	99,013,231	0	2,588,340	0	101,601,570
72	AMORTIZATION OF LIMITED TERM PLANT	4,943,918	504,115	5,448,033	0	0	0	803,109	0	6,251,142	0	4,104	0	6,255,245
73	TAXES OTHER THAN INCOME	19,083,954	(0)	19,083,954	29,660	0	0	1,050,950	0	20,164,564	488,490	72,575	0	20,725,629
74	REGULATORY DEBITS/CREDITS	(3,781,013)	3,781,013	0	0	0	0	0	0	0	0	0	0	0
75	PROVISION FOR DEFERRED INCOME TAXES	40,319,488	0	40,319,488	0	0	0	0	(4,261,587)	36,057,901	0	0	0	36,057,901
76	INVESTMENT TAX CREDIT ADJUSTMENT	2,269,367	0	2,269,367	0	0	0	0	(3,226,936)	(957,569)	0	0	0	(957,569)
77	FEDERAL INCOME TAXES	(1,816,783)	(8,524,776)	(10,341,559)	(147,540)	(967,298)	0	(3,979,591)	8,803,339	(6,632,650)	14,744,010	(5,087,863)	(1,215,721)	1,807,776
78	STATE INCOME TAXES	(4,930,646)	(1,637,630)	(6,568,277)	(28,343)	(185,820)	0	(764,489)	3,986,231	(3,560,698)	2,832,361	(977,391)	(233,543)	(1,939,271)
79	TOTAL OPERATING EXPENSES	802,542,203	(99,072,064)	703,470,139	(146,223)	1,796,411	0	1,051,313	5,606,027	711,777,668	31,198,791	6,489,094	2,257,768	751,723,321
80	OPERATING INCOME	153,533,362	(5,610,570)	147,922,791	(274,003)	(1,796,411)	0	(7,390,669)	(5,606,027)	132,855,679	27,381,734	(6,489,094)	(2,257,768)	151,490,551
81	ADD: IERCO OPERATING INCOME	5,086,761	(337,988)	4,748,773	0	0	0	1,380,094	0	6,128,867	0	0	0	6,128,867
82	CONSOLIDATED OPERATING INCOME	158,620,123	(5,948,558)	152,671,564	(274,003)	(1,796,411)	0	(6,010,575)	(5,606,027)	138,984,546	27,381,734	(6,489,094)	(2,257,768)	157,619,418

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Jeannette Bowman
Summary of Adjustments - Electric Plant in Service

July 31, 2009

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2009

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
		2008	2008	2008	2008 to 2009 Forecast Adjustments					2009 Unadjusted	Normalizing	Annualizing	Known & Measurable	2009
	Description	Actuals	Adjustments	Base	3-Yr	O&M	Growth %	Fixed	Other	Forecast Year	Adjustments	Adjustments	Adjustments	Test Year
100	***TABLE 1-ELECTRIC PLANT IN SERVICE***													
101	INTANGIBLE PLANT													
102	301 - ORGANIZATION	9,568		9,568				46,379		55,947	0	0	0	55,947
103	302 - FRANCHISES & CONSENTS	21,725,717		21,725,717				15,592		21,741,309	0	0	0	21,741,309
104	303 - MISCELLANEOUS	27,403,492		27,403,492				3,106,800		30,510,292	0	0	0	30,510,292
105														
106	TOTAL INTANGIBLE PLANT	49,138,777		49,138,777				3,168,771		52,307,548	0	0	0	52,307,548
107														
108	PRODUCTION PLANT													
109	310-316 / STEAM PRODUCTION	872,887,048		872,887,048				16,100,651		888,987,699	0	5,466,570	0	894,454,269
110	330-336 / HYDRAULIC PRODUCTION	674,846,329		674,846,329				14,903,960		689,750,289	0	480,231	0	690,230,520
111	340-346 / OTHER PRODUCTION	150,205,736		150,205,736				14,990,138		165,195,873	0	0	0	165,195,873
112														
113	TOTAL PRODUCTION PLANT	1,697,939,113		1,697,939,113				45,994,749		1,743,933,861	0	5,946,801	0	1,749,880,662
114														
115	TRANSMISSION PLANT													
116	350 / LAND & LAND RIGHTS - SYSTEM SERVICE	31,564,161		31,564,161				(3,119,802)		28,444,359	0	0	0	28,444,359
117	TRANSMISSION RETAIL	252,850		252,850				0		252,850	0	0	0	252,850
118	DIRECT ASSIGNMENT	187,730		187,730				0		187,730	0	0	0	187,730
119	TOTAL ACCOUNT 350	32,004,741		32,004,741				(3,119,802)		28,884,939	0	0	0	28,884,939
120														0
121	352 / STRUCTURES & IMPROVEMENTS - SYSTEM SERVICE	38,496,327		38,496,327				2,193,921		40,690,247	0	0	0	40,690,247
122	TRANSMISSION RETAIL	2,169,976		2,169,976				0		2,169,976	0	0	0	2,169,976
123	DIRECT ASSIGNMENT	230,972		230,972				0		230,972	0	0	0	230,972
124	TOTAL ACCOUNT 352	40,897,275		40,897,275				2,193,921		43,091,195	0	0	0	43,091,195
125														0
126	353 / STATION EQUIPMENT - SYSTEM SERVICE	251,948,934		251,948,934				24,872,233		276,821,167	0	3,622,745	0	280,443,912
127	TRANSMISSION RETAIL	18,471,409		18,471,409				0		18,471,409	0	0	0	18,471,409
128	DIRECT ASSIGNMENT	2,390,275		2,390,275				0		2,390,275	0	0	0	2,390,275
129	TOTAL ACCOUNT 353	272,810,618		272,810,618				24,872,233		297,682,851	0	3,622,745	0	301,305,596
130														0
131	354 / TOWERS & FIXTURES - SYSTEM SERVICE	125,386,959		125,386,959				15,324,371		140,711,330	0	0	0	140,711,330
132	TRANSMISSION RETAIL	0		0				0		0	0	0	0	0
133	DIRECT ASSIGNMENT	186,616		186,616				0		186,616	0	0	0	186,616
134	TOTAL ACCOUNT 354	125,573,575		125,573,575				15,324,371		140,897,946	0	0	0	140,897,946
135														
136	355 / POLES & FIXTURES - SYSTEM SERVICE	87,045,841		87,045,841				4,079,631		91,125,472	0	0	0	91,125,472
137	TRANSMISSION RETAIL	36,341		36,341				0		36,341	0	0	0	36,341
138	DIRECT ASSIGNMENT	2,995,391		2,995,391				0		2,995,391	0	0	0	2,995,391
139	TOTAL ACCOUNT 355	90,077,573		90,077,573				4,079,631		94,157,204	0	0	0	94,157,204
140														
141	356 / OVERHEAD CONDUCTORS & DEVICES - SYSTEM SERVIC	142,391,435		142,391,435				7,942,127		150,333,562	0	1,257,482	0	151,591,044
142	TRANSMISSION RETAIL	162,048		162,048				0		162,048	0	0	0	162,048
143	DIRECT ASSIGNMENT	2,149,803		2,149,803				0		2,149,803	0	0	0	2,149,803
144	TOTAL ACCOUNT 356	144,703,286		144,703,286				7,942,127		152,645,413	0	1,257,482	0	153,902,895
145														
146	359 / ROADS & TRAILS - SYSTEM SERVICE	303,364		303,364				0		303,364	0	0	0	303,364
147	TRANSMISSION RETAIL	0		0				0		0	0	0	0	0
148	DIRECT ASSIGNMENT	14,987		14,987				0		14,987	0	0	0	14,987
149	TOTAL ACCOUNT 359	318,351		318,351				0		318,351	0	0	0	318,351
150														
151	TOTAL TRANSMISSION PLANT	706,385,420		706,385,420				51,292,481		757,677,901	0	4,880,227	0	762,558,128

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2009

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
		2008	2008	2008	2008 to 2009 Forecast Adjustments					2009 Unadjusted	Normalizing	Annualizing	Known & Measurable	2009
	Description	Actuals	Adjustments	Base	3-Yr	O&M	Growth %	Fixed	Other	Forecast Year	Adjustments	Adjustments	Adjustments	Test Year
152	***TABLE 1-ELECTRIC PLANT IN SERVICE***													0
153														0
154	DISTRIBUTION PLANT													0
155	360 / LAND & LAND RIGHTS - SYSTEM SERVICE	4,568,498		4,568,498				94,197		4,662,695	0	0	0	4,662,695
156	DIRECT ASSIGNMENT	2,953		2,953				0		2,953	0	0	0	2,953
157	NET DISTRIBUTION PLANT	4,571,451		4,571,451				94,197		4,665,648	0	0	0	4,665,648
158	PLUS: ADJUSTMENT FOR CIAC	89,389		89,389				0		89,389				89,389
159	NET DISTRIBUTION PLANT + CIAC	4,660,840		4,660,840				94,197		4,755,037	0	0	0	4,755,037
160														0
161	361 / STRUCTURES & IMPROVEMENTS - SYSTEM SERVICE	22,656,904		22,656,904				2,959,681		25,616,586	0	0	0	25,616,586
162	DIRECT ASSIGNMENT	271,060		271,060				0		271,060	0	0	0	271,060
163	NET DISTRIBUTION PLANT	22,927,964		22,927,964				2,959,681		25,887,646	0	0	0	25,887,646
164	PLUS: ADJUSTMENT FOR CIAC	4,463,307		4,463,307				0		4,463,307				4,463,307
165	NET DISTRIBUTION PLANT + CIAC	27,391,271		27,391,271				2,959,681		30,350,953	0	0	0	30,350,953
166														0
167	362 / STATION EQUIPMENT - SYSTEM SERVICE	155,989,487		155,989,487				15,049,880		171,039,367	0	2,706,145	0	173,745,512
168	DIRECT ASSIGNMENT	1,575,234		1,575,234				0		1,575,234	0	0	0	1,575,234
169	NET DISTRIBUTION PLANT	157,564,721		157,564,721				15,049,880		172,614,601	0	2,706,145	0	175,320,746
170	PLUS: ADJUSTMENT FOR CIAC	18,276,721		18,276,721				0		18,276,721				18,276,721
171	NET DISTRIBUTION PLANT + CIAC	175,841,442		175,841,442				15,049,880		190,891,322	0	2,706,145	0	193,597,467
172														0
173	364 / POLES, TOWERS & FIXTURES	206,739,181		206,739,181				8,865,332		215,604,513	0	0	0	215,604,513
174	365 / OVERHEAD CONDUCTORS & DEVICES	109,387,114		109,387,114				10,171,009		119,558,122	0	114,081	0	119,672,203
175	366 / UNDERGROUND CONDUIT	46,883,582		46,883,582				1,406,463		48,290,046	0	0	0	48,290,046
176	367 / UNDERGROUND CONDUCTORS & DEVICES	174,801,765		174,801,765				8,520,467		183,322,233	0	3,868,724	0	187,190,957
177	368 / LINE TRANSFORMERS	366,975,446		366,975,446				19,331,340		386,306,786	0	0	0	386,306,786
178	369 / SERVICES	54,698,081		54,698,081				1,359,053		56,057,134	0	0	0	56,057,134
179	370 / METERS	56,925,294		56,925,294				8,905,614		65,830,908	0	0	0	65,830,908
180	371 / INSTALLATIONS ON CUSTOMER PREMISES	2,574,382		2,574,382				(5,549)		2,568,833	0	0	0	2,568,833
181	373 / STREET LIGHTING SYSTEMS	4,134,967		4,134,967				42,125		4,177,092	0	0	0	4,177,092
182														0
183	TOTAL DISTRIBUTION PLANT	1,208,183,947		1,208,183,947				76,699,612		1,284,883,560	0	6,688,950	0	1,291,572,510
184														0
185	GENERAL PLANT													0
186	389 / LAND & LAND RIGHTS	10,730,782		10,730,782				(11,377)		10,719,405	0	0	0	10,719,405
187	390 / STRUCTURES & IMPROVEMENTS	70,130,198		70,130,198				6,107,984		76,238,183	0	888,462	0	77,126,645
188	391 / OFFICE FURNITURE & EQUIPMENT	45,453,808		45,453,808				5,136,925		50,590,733	0	0	0	50,590,733
189	392 / TRANSPORTATION EQUIPMENT	57,516,328		57,516,328				548,483		58,064,811	0	0	0	58,064,811
190	393 / STORES EQUIPMENT	1,101,003		1,101,003				110,383		1,211,387	0	0	0	1,211,387
191	394 / TOOLS, SHOP & GARAGE EQUIPMENT	4,666,735		4,666,735				335,158		5,001,892	0	0	0	5,001,892
192	395 / LABORATORY EQUIPMENT	10,741,095		10,741,095				496,735		11,237,831	0	0	0	11,237,831
193	396 / POWER OPERATED EQUIPMENT	8,651,794		8,651,794				299,171		8,950,965	0	0	0	8,950,965
194	397 / COMMUNICATIONS EQUIPMENT	26,481,070		26,481,070				2,553,580		29,034,650	0	164,154	0	29,198,804
195	398 / MISCELLANEOUS EQUIPMENT	3,823,275		3,823,275				779,255		4,602,530	0	0	0	4,602,530
196														
197	TOTAL GENERAL PLANT	239,296,089		239,296,089				16,356,298		255,652,387	0	1,052,616	0	256,705,003
198														
199	TOTAL ELECTRIC PLANT IN SERVICE	3,900,943,345		3,900,943,345				193,511,911		4,094,455,256	0	18,568,594	0	4,113,023,850

Idaho Power/703
Witness: Jeannette Bowman

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Jeannette Bowman
Summary of Adjustments - Accumulated Provision for Depreciation & Amortization

July 31, 2009

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2009

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
		2008	2008	2008	2008 to 2009 Forecast Adjustments					2009 Unadjusted	Normalizing	Annualizing	Known & Measurable	2009
	Description	Actuals	Adjustments	Base	3-Yr	O&M	Growth %	Fixed	Other	Forecast Year	Adjustments	Adjustments	Adjustments	Test Year
200	***TABLE 2-ACCUMULATED PROVISION FOR DEPRECIATION***													
201														
202	PRODUCTION PLANT													
203	310-316 / STEAM PRODUCTION	535,265,663		535,265,663				6,404,362		541,670,025	0	63,709	0	541,733,734
204	330-336 / HYDRAULIC PRODUCTION	303,441,038		303,441,038				14,208,653		317,649,691	0	66,381	0	317,716,072
205	340-346 / OTHER PRODUCTION	13,347,840		13,347,840				5,595,800		18,943,640	0	3,961	0	18,947,600
206	TOTAL PRODUCTION PLANT	852,054,541		852,054,541				26,208,814		878,263,356	0	134,050	0	878,397,406
207														
208	TRANSMISSION PLANT													
209	350 / LAND & LAND RIGHTS	5,074,247		5,074,247				(222,553)		4,851,695	0	0	0	4,851,695
210	352 / STRUCTURES & IMPROVEMENTS	19,233,523		19,233,523				638,680		19,872,203	0	10,885	0	19,883,088
211	353 / STATION EQUIPMENT	84,645,863		84,645,863				2,328,470		86,974,333	0	83,532	0	87,057,864
212	354 / TOWERS & FIXTURES	33,037,292		33,037,292				2,620,768		35,658,060	0	40,325	0	35,698,385
213	355 / POLES & FIXTURES	45,917,539		45,917,539				1,542,451		47,459,990	0	15,786	0	47,475,776
214	356 / OVERHEAD CONDUCTORS & DEVICES	47,198,941		47,198,941				1,572,985		48,771,926	0	22,640	0	48,794,565
215	359 / ROADS & TRAILS	248,833		248,833				3,176		252,010	0	0	0	252,010
216	TOTAL TRANSMISSION PLANT	235,356,238		235,356,238				8,483,977		243,840,216	0	173,167	0	244,013,383
217														
218	DISTRIBUTION PLANT													
219	360 / LAND & LAND RIGHTS	0		0				0		0	0	0	0	0
220	361 / STRUCTURES & IMPROVEMENTS	7,324,986		7,324,986				419,596		7,744,583	0	17,520	0	7,762,103
221	362 / STATION EQUIPMENT	39,400,440		39,400,440				2,063,718		41,464,158	0	70,587	0	41,534,744
222	364 / POLES, TOWERS & FIXTURES	96,665,182		96,665,182				5,475,957		102,141,139	0	90,846	0	102,231,985
223	365 / OVERHEAD CONDUCTORS & DEVICES	38,040,301		38,040,301				1,988,676		40,028,976	0	45,813	0	40,074,790
224	366 / UNDERGROUND CONDUIT	9,794,280		9,794,280				840,220		10,634,500	0	8,063	0	10,642,563
225	367 / UNDERGROUND CONDUCTORS & DEVICES	60,324,540		60,324,540				2,867,147		63,191,688	0	33,959	0	63,225,647
226	368 / LINE TRANSFORMERS	137,830,434		137,830,434				1,012,503		138,842,936	0	39,027	0	138,881,963
227	369 / SERVICES	33,313,903		33,313,903				1,289,777		34,603,680	0	7,297	0	34,610,977
228	370 / METERS	10,294,476		10,294,476				3,361,530		13,656,006	0	262,908	0	13,918,914
229	371 / INSTALLATIONS ON CUSTOMER PREMISES	2,547,777		2,547,777				(135,076)		2,412,700	0	129	0	2,412,829
230	373 / STREET LIGHTING SYSTEMS	2,982,433		2,982,433				124,390		3,106,823	0	318	0	3,107,141
231	TOTAL DISTRIBUTION PLANT	438,518,751		438,518,751				19,308,438		457,827,189	0	576,467	0	458,403,656
232														

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2009

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
		2008	2008	2008	2008 to 2009 Forecast Adjustments					2009 Unadjusted	Normalizing	Annualizing	Known & Measurable	2009
	Description	Actuals	Adjustments	Base	3-Yr	O&M	Growth %	Fixed	Other	Forecast Year	Adjustments	Adjustments	Adjustments	Test Year
233	***TABLE 2-ACCUMULATED PROVISION FOR DEPRECIATION***													
234														
235	GENERAL PLANT													
236	389 / LAND & LAND RIGHTS	0		0				0		0	0	0	0	0
237	390 / STRUCTURES & IMPROVEMENTS	18,768,090		18,768,090				1,050,411		19,818,502	0	22,836	0	19,841,338
238	391 / OFFICE FURNITURE & EQUIPMENT	20,618,384		20,618,384				4,334,052		24,952,436	0	291,270	0	25,243,706
239	392 / TRANSPORTATION EQUIPMENT	19,706,251		19,706,251				(1,386,402)		18,319,849	0	3,097	0	18,322,947
240	393 / STORES EQUIPMENT	498,572		498,572				35,434		534,006	0	1,523	0	535,529
241	394 / TOOLS, SHOP & GARAGE EQUIPMENT	2,250,950		2,250,950				94,992		2,345,941	0	3,957	0	2,349,899
242	395 / LABORATORY EQUIPMENT	5,211,297		5,211,297				187,538		5,398,835	0	11,547	0	5,410,382
243	396 / POWER OPERATED EQUIPMENT	2,328,930		2,328,930				258,259		2,587,189	0	10,005	0	2,597,195
244	397 / COMMUNICATIONS EQUIPMENT	13,068,108		13,068,108				844,771		13,912,880	0	63,393	0	13,976,273
245	398 / MISCELLANEOUS EQUIPMENT	1,320,992		1,320,992				246,560		1,567,552	0	15,959	0	1,583,511
246	TOTAL GENERAL PLANT	83,771,575		83,771,575				5,665,615		89,437,190	0	423,588	0	89,860,778
247														
248	AMORTIZATION OF DISALLOWED COSTS	7,741,883		7,741,883				(296,299)		7,445,584	0	0	0	7,445,584
249														
250	TOTAL ACCUM PROVISION DEPRECIATION	1,617,442,989		1,617,442,989				59,370,545		1,676,813,534	0	1,307,272	0	1,678,120,806
251														
252	AMORTIZATION OF OTHER UTILITY PLANT													
253	INTANGIBLE PLANT	17,908,337		17,908,337				(449,091)		17,459,246	0	2,052	0	17,461,298
254	HYDRAULIC PRODUCTION	0		0				0		0	0	0	0	
255														
256	TOTAL AMORT OF OTHER UTILITY PLANT	17,908,337		17,908,337				(449,091)		17,459,246	0	2,052	0	17,461,298
257														
258	TOTAL ACCUM PROVISION FOR DEPR													
259	& AMORTIZATION OF OTHER UTILITY PLANT	1,635,351,326		1,635,351,326				58,921,454		1,694,272,780	0	1,309,324	0	1,695,582,104
260														

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Jeannette Bowman
Summary of Adjustments - Additions & Deletions to Rate Base

July 31, 2009

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2009

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
		2008	2008	2008	2008 to 2009 Forecast Adjustments					2009 Unadjusted	Normalizing	Annualizing	Known & Measurable	2009
	Description	Actuals	Adjustments	Base	3-Yr	O&M	Growth %	Fixed	Other	Forecast Year	Adjustments	Adjustments	Adjustments	Test Year
261	***TABLE 3-ADDITIONS & DEDUCTIONS TO RATEBASE***													0
262														0
263	NET ELECTRIC PLANT IN SERVICE	2,265,592,019		2,265,592,019				134,590,457		2,400,182,476	0	17,259,270	0	2,417,441,746
264	LESS:													0
265	252 CUSTOMER ADVANCES FOR CONSTRUCTION													
266	POWER SUPPLY	0		0				0		0	0	0	0	0
267	OTHER	31,785,562		31,785,562				(7,421,498)		24,364,064	0	0	0	24,364,064
268	TOTAL CUSTOMER ADV FOR CONSTRUCTION	31,785,562		31,785,562				(7,421,498)		24,364,064	0	0	0	24,364,064
269														
270	ACCUMULATED DEFERRED INCOME TAXES													
271	190 / ACCUMULATED DEFERRED INCOME TAXES	(26,338,519)	(323,604)	(26,662,123)					1,650,257	(25,011,866)	0	0	0	(25,011,866)
272	281 / ACCELERATED AMORTIZATION	0		0						0	0	0	0	0
273	282 / OTHER PROPERTY	231,516,781		231,516,781					22,647,884	254,164,665	0	0	0	254,164,665
274	283 / OTHER	3,309,495	3,421	3,312,916					(1,425,852)	1,887,064	0	0	0	1,887,064
275	TOTAL ACCUM DEFERRED INCOME TAXES	208,487,757	(320,183)	208,167,574					22,872,289	231,039,863	0	0	0	231,039,863
276														
277	NET ELECTRIC PLANT IN SERVICE	2,025,318,700	320,183	2,025,638,883	0	0		142,011,955	(22,872,289)	2,144,778,549	0	17,259,270	0	2,162,037,819
278	ADD:													
279	WORKING CAPITAL													
280	151 / FUEL INVENTORY	20,591,474		20,591,474						20,591,474	(2,889,043)	0	0	17,702,431
281	154 & 163 / PLANT MATERIALS & SUPPLIES													
282	PRODUCTION - GENERAL	13,667,291		13,667,291						13,667,291	0	0	0	13,667,291
283	TRANSMISSION - GENERAL	9,590,873		9,590,873						9,590,873	0	0	0	9,590,873
284	DISTRIBUTION - GENERAL	20,320,626		20,320,626						20,320,626	0	0	0	20,320,626
285	OTHER - UNCLASSIFIED	4,989,717		4,989,717						4,989,717	0	0	0	4,989,717
286	TOTAL ACCOUNT 154 & 163	48,568,507		48,568,507						48,568,507	0	0	0	48,568,507
287	165 / PREPAID ITEMS													
288	AD VALOREM TAXES	1,488,445	(1,488,445)	0						0	0	0	0	0
289	OTHER PROD-RELATED PREPAYMENTS	508,964	(508,964)	0						0	0	0	0	0
290	INSURANCE	3,140,965	(3,140,965)	0						0	0	0	0	0
291	PENSION EXPENSE	710,819	(710,819)	0						0	0	0	0	0
292	PREPAID CONTRACTS	2,598,564	(2,598,564)	0						0	0	0	0	0
293	MISCELLANEOUS PREPAYMENTS	1,417,598	(1,417,598)	0						0	0	0	0	0
294	TOTAL ACCOUNT 165	9,865,355	(9,865,355)	0						0	0	0	0	0
295	WORKING CASH ALLOWANCE	25,992,653	(3,727,791)	22,264,862	0	117,981		62,628	12,199	22,457,670	525,357	395,573	148,281	23,526,882
296														
297	TOTAL WORKING CAPITAL	105,017,990	(13,593,147)	91,424,843	0	117,981		62,628	12,199	91,617,651	(2,363,686)	395,573	148,281	89,797,820
298														
299	NET ELECTRIC PLANT IN SERVICE	2,130,336,690	(13,272,964)	2,117,063,726	0	117,981		142,074,583	(22,860,090)	2,236,396,200	(2,363,686)	17,654,843	148,281	2,251,835,639

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2009

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
		2008	2008	2008	2008 to 2009 Forecast Adjustments					2009 Unadjusted	Normalizing	Annualizing	Known & Measurable	2009
	Description	Actuals	Adjustments	Base	3-Yr	O&M	Growth %	Fixed	Other	Forecast Year	Adjustments	Adjustments	Adjustments	Test Year
300	***TABLE 3-ADDITIONS & DEDUCTIONS TO RATEBASE***													
301														
302	NET ELECTRIC PLANT IN SERVICE	2,130,336,690	(13,272,964)	2,117,063,726	0	117,981		142,074,583	(22,860,090)	2,236,396,200	(2,363,686)	17,654,843	148,281	2,251,835,639
303	ADD:													
304	105 / PLANT HELD FOR FUTURE USE													
305	HYDRAULIC PRODUCTION	112,703	(112,703)	0						0	0	0	0	0
306	TRANS LAND & LAND RIGHTS	607,894	(83,175)	524,719						524,719	0	0	0	524,719
307	TRANS STRUCTURES & IMPROVEMENTS	361,413	(361,413)	0						0	0	0	0	0
308	TRANS STATION EQUIPMENT	32,400	(32,400)	0						0	0	0	0	0
309	DIST LAND & LAND RIGHTS	1,623,660	(569,661)	1,053,999						1,053,999	0	0	0	1,053,999
310	DIST STRUCTURES & IMPROVEMENTS	61,518	(61,518)	0						0	0	0	0	0
311	GEN LAND & LAND RIGHTS	3,398,789	0	3,398,789						3,398,789	0	0	0	3,398,789
312	GEN STRUCTURES & IMPROVEMENTS	72,785	(72,785)	0						0	0	0	0	0
313	TRANSPORTATION EQUIPMENT	47,000	(47,000)	0						0	0	0	0	0
314	TOTAL PLANT HELD FOR FUTURE USE	6,318,163	(1,340,655)	4,977,507						4,977,507	0	0	0	4,977,507
315														
316	114/115 - PRAIRIE ACQUISITION ADJ (ACCOUNT 406)	0	(81,423)	(81,423)						(81,423)	0	0	0	(81,423)
317														
318	DEFERRED PROGRAMS:													
319	182 / CONSERVATION PROGRAMS													
320	IDAHO DEFERRED CONSERVATION PROGRAMS	4,863,935		4,863,935				(3,242,604)		1,621,331	0	0	0	1,621,331
321	OREGON DEFERRED CONSERVATION PROGRAMS	0		0						0	0	0	0	0
322	TOTAL CONSERVATION PROGRAMS	4,863,935		4,863,935						1,621,331	0	0	0	1,621,331
323	182 / MISC. OTHER REGULATORY ASSETS													
324	REORGANIZATION COSTS	0		0						0	0	0	0	0
325	ZGA ARCHITECTS & PLANNERS	0		0				7,395		7,395	0	0	0	7,395
326	PROFESSIONAL FEES	0		0				0		0	0	0	0	0
327	INTERVENOR FUNDING	77,308		77,308				(71,577)		5,731	0	0	0	5,731
328	GRID WEST - OPUC ORDER 06-483	64,994		64,994				4,757		69,751	0	0	2,442	72,193
329	GRID WEST - FERC	363,117		363,117				(83,796)		279,321	0	0	0	279,321
330	TOTAL OTHER REGULATORY ASSETS	505,419		505,419				(143,221)		362,198	0	0	2,442	364,640
331	186 / MISC. OTHER DEFERRED PROGRAMS							0						
332	AM. FALLS BOND REFINANCING	1,011,247		1,011,247				(62,551)		948,696	0	0	0	948,696
333	TOTAL DEFERRED PROGRAMS	6,380,601		6,380,601				(3,448,376)		2,932,225	0	0	2,442	2,934,667
334								0						
335	DEVELOPMENT OF IERCO RATE BASE							0						
336	INVESTMENT IN IERCO	56,170,192	(85,531)	56,084,661				6,340,341		62,425,002	0	0		62,425,002
337	PREPAID COAL ROYALTIES	1,612,065		1,612,065				(69,325)		1,542,740	0	0	0	1,542,740
338	NOTES PAYABLE TO/RECEIVABLE FROM SUBSIDIARY	25,580,108		25,580,108				(2,206,678)		23,373,430	0	0	0	23,373,430
339	TOTAL SUBSIDIARY RATE BASE	83,362,365	(85,531)	83,276,834				4,064,338		87,341,172	0	0	0	87,341,172
340								0						
341	TOTAL COMBINED RATE BASE	2,226,397,818	(14,780,573)	2,211,617,245	0	117,981		142,690,545	(22,860,090)	2,331,565,681	(2,363,686)	17,654,843	150,723	2,347,007,562

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Jeannette Bowman
Summary of Adjustments - Operating Revenues

July 31, 2009

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2009

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
			2008	2008	2008	2008 to 2009 Forecast Adjustments					2009 Unadjusted	Normalizing	Annualizing	Known & Measurable	2009
		Description	Actuals	Adjustments	Base	3-Yr	O&M	Growth %	Fixed	Other	Forecast Year	Adjustments	Adjustments	Adjustments	Test Year
342	***TABLE 4-OPERATING REVENUES***														
343	FIRM ENERGY SALES & OATT REFUNDS														
344	440-448 / RETAIL		784,310,742	(92,160,402)	692,150,340						692,150,340	49,838,391	0	0	741,988,731
345	440-REVENUE OFFSET FOR PLANT ADDITIONS		0	0	0						0	0	0	0	0
346	447 / FIRM SALES FOR RESALE		2,487,232	(448,032)	2,039,200						2,039,200	59,634	0	0	2,098,834
347	447 / SYSTEM OPPORTUNITY SALES		118,941,593	(4,679,193)	114,262,400						114,262,400	8,682,500	0	0	122,944,900
348	TOTAL SALES OF ELECTRICITY		905,739,567	(97,287,627)	808,451,940				0		808,451,940	58,580,525	0	0	867,032,465
349															
350	OTHER OPERATING REVENUES														
351	415 / MERCHANDISING REVENUES		0	1,505,432	1,505,432				*(658,334)*		847,098	0	0	0	847,098
352															
353	449 / OATT TARIFF REFUND														
354	4 NETWORK		(6,863,394)	6,863,394	0						0	0	0	0	0
355	POINT-TO-POINT		(3,116,442)	3,116,442	0						0	0	0	0	0
356	TOTAL ACCOUNT 449		(9,979,836)	9,979,836	0						0	0	0	0	0
357															
358	451 / MISCELLANEOUS SERVICE REVENUES		3,669,976		3,669,976	(651,421)		-17.75%			3,018,555	0	0	0	3,018,555
359															
360	454 / RENTS FROM ELECTRIC PROPERTY														
361	SUBSTATION EQUIPMENT		7,114,492		7,114,492						7,114,492	0	0	0	7,114,492
362	TRANSFORMER RENTALS		17,330		17,330						17,330	0	0	0	17,330
363	LINE RENTALS		2,039,614		2,039,614						2,039,614	0	0	0	2,039,614
364	COGENERATION		546,786		546,786	25,480		4.66%			572,266	0	0	0	572,266
365	REAL ESTATE RENTS		330,426		330,426	10,144		3.07%			340,570	0	0	0	340,570
366	DARK FIBER PROJECT		447,361		447,361	(313)		-0.07%			447,047	0	0	0	447,047
367	POLE ATTACHMENTS		1,505,132		1,505,132	(68,333)		-4.54%			1,436,799	0	0	0	1,436,799
368	FACILITIES CHARGES		6,561,257		6,561,257	262,450		4.00%			6,823,707	0	0	0	6,823,707
369	OTHER RENTALS		327,242		327,242	1,767		0.54%			329,009	0	0	0	329,009
370	MISCELLANEOUS		0		0						0	0	0	0	0
371	TOTAL ACCOUNT 454		18,889,640		18,889,640	231,195					19,120,834	0	0	0	19,120,834
372															
373	456 / OTHER ELECTRIC REVENUES														
374	TRANSMISSION - NETWORK SERVICES		5,411,638		5,411,638				(772,514)		4,639,124	0	0	0	4,639,124
375	TRANSMISSION - POINT-TO-POINT		12,911,651		12,911,651				(4,908,508)		8,003,143	0	0	0	8,003,143
376	PHOTOVOLTAIC STATION SERVICE		11,601		11,601				0		11,601	0	0	0	11,601
377	ANTELOPE		73,824		73,824				0		73,824	0	0	0	73,824
378	ALTERNATIVE TRANSMISSION SERVICE CHARGE		0		0				0		0	0	0	0	0
379	SIERRA PACIFIC USAGE CHARGE		103,087		103,087				0		103,087	0	0	0	103,087
380	STAND-BY SERVICE		288,494		288,494				0		288,494	0	0	0	288,494
381	ENERGY EFFICIENCY RIDER		18,880,276	(18,880,276)	0				0		0	0	0	0	0
382	MISCELLANEOUS		75,647		75,647				0		75,647	0	0	0	75,647
383	TOTAL ACCOUNT 456		37,756,218	(18,880,276)	18,875,942	0			(5,681,022)		13,194,920	0	0	0	13,194,920
384															
385	TOTAL OTHER OPERATING REVENUES		50,335,998	(7,395,008)	42,940,990	(420,226)			(6,339,356)		36,181,407	0	0	0	36,181,407
386															
387	TOTAL OPERATING REVENUES		956,075,565	(104,682,635)	851,392,930	(420,226)			(6,339,356)	0	844,633,347	58,580,525	0	0	903,213,872

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Jeannette Bowman
Summary of Adjustments - Operation & Maintenance Expenses

July 31, 2009

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2009

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
		2008	2008	2008	2008 to 2009 Forecast Adjustments					2009 Unadjusted	Normalizing	Annualizing	Known & Measurable	2009
	Description	Actuals	Adjustments	Base	3-Yr	O&M	Growth %	Fixed	Other	Forecast Year	Adjustments	Adjustments	Adjustments	Test Year
388	***TABLE 5-OPERATION & MAINTENANCE EXPENSES***													
389	STEAM POWER GENERATION													
390	OPERATION													
391	500 / SUPERVISION & ENGINEERING	1,650,284	(21)	1,650,263		60,730	3.68%			1,710,993		7,093	8,436	1,726,522
392	501 / FUEL	132,015,163	1,391,137	133,406,300					0	133,406,300	2,103,900	0	0	135,510,200
393	502 / STEAM EXPENSES													
394	LABOR	2,435,969		2,435,969		0	3.68%			2,435,969				2,435,969
395	OTHER	4,940,720		4,940,720		271,462	3.68%			5,212,182				5,212,182
396	TOTAL ACCOUNT 502	7,376,689		7,376,689		271,462	3.68%	0	0	7,648,151	0	0	0	7,648,151
397	505 / ELECTRIC EXPENSES													0
398	LABOR	987,738		987,738		0	3.68%			987,738				987,738
399	OTHER	830,222		830,222		66,901	3.68%			897,123				897,123
400	TOTAL ACCOUNT 505	1,817,960		1,817,960		66,901	3.68%	0	0	1,884,861	0	0	0	1,884,861
401	506 / MISCELLANEOUS EXPENSES	7,737,497		7,737,497		284,740				8,022,237		308	366	8,022,911
402	507 / RENTS	469,699		469,699		17,285	3.68%			486,984				486,984
403	STEAM OPERATION EXPENSES	151,067,292	1,391,116	152,458,408		701,118		0	0	153,159,526	2,103,900	7,401	8,802	155,279,629
404														
405	MAINTENANCE													
406	510 / SUPERVISION & ENGINEERING	2,567,722		2,567,722		94,492	3.68%			2,662,214				2,662,214
407	511 / STRUCTURES	398,714		398,714		14,673	3.68%			413,387				413,387
408	512 / BOILER PLANT													0
409	LABOR	6,108,665		6,108,665		0	3.68%			6,108,665				6,108,665
410	OTHER	8,096,378		8,096,378		522,746	3.68%			8,619,124				8,619,124
411	TOTAL ACCOUNT 512	14,205,043		14,205,043		522,746	3.68%	0	0	14,727,789	0	0	0	14,727,789
412	513 / ELECTRIC PLANT													
413	LABOR	1,856,398		1,856,398		0	3.68%			1,856,398				1,856,398
414	OTHER	2,444,752		2,444,752		158,282	3.68%			2,603,034				2,603,034
415	TOTAL ACCOUNT 513	4,301,150		4,301,150		158,282	3.68%	0	0	4,459,432	0	0	0	4,459,432
416	514 / MISCELLANEOUS STEAM PLANT	4,322,931		4,322,931		159,084	3.68%			4,482,015				4,482,015
417	STEAM MAINTENANCE EXPENSES	25,795,560	0	25,795,560		949,277		0	0	26,744,837	0	0	0	26,744,837
418	TOTAL STEAM GENERATION EXPENSES	176,862,852	1,391,116	178,253,968		1,650,395		0	0	179,904,363	2,103,900	7,401	8,802	182,024,466
419														

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2009

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
		2008	2008	2008	2008 to 2009 Forecast Adjustments					2009 Unadjusted	Normalizing	Annualizing	Known & Measurable	2009
	Description	Actuals	Adjustments	Base	3-Yr	O&M	Growth %	Fixed	Other	Forecast Year	Adjustments	Adjustments	Adjustments	Test Year
420	***TABLE 5-OPERATION & MAINTENANCE EXPENSES***													
421	HYDRAULIC POWER GENERATION													
422	OPERATION													
423	535 / SUPERVISION & ENGINEERING	5,602,490	(220)	5,602,270		197,760	3.53%			5,800,030		118,897	141,405	6,060,332
424	536 / WATER FOR POWER	7,355,741	(251)	7,355,490		180,162	3.53%			7,535,652		11,075	13,172	7,559,899
425	537 / HYDRAULIC EXPENSES	9,978,474	(1,526)	9,976,948		352,186	3.53%			10,329,134		118,245	140,630	10,588,009
426	538 / ELECTRIC EXPENSES													
427	LABOR	933,699		933,699		32,959	3.53%			966,658		27,917	33,202	1,027,777
428	OTHER	378,887		378,887		13,375	3.53%			392,262				392,262
429	TOTAL ACCOUNT 538	1,312,586		1,312,586		46,334	3.53%	0	0	1,358,920	0	27,917	33,202	1,420,039
430	539 / MISCELLANEOUS EXPENSES	3,091,677	(593)	3,091,084		109,115	3.53%			3,200,199				3,200,199
431	540 / RENTS	431,893		431,893		15,246	3.53%			447,139		56,203	66,843	570,185
432	HYDRAULIC OPERATION EXPENSES	27,772,861	(2,590)	27,770,271		900,803		0	0	28,671,074	0	332,337	395,252	29,398,663
433														
434	MAINTENANCE													
435	541 / SUPERVISION & ENGINEERING	1,885,154	(712)	1,884,442		66,521	3.53%			1,950,963		46,279	55,040	2,052,282
436	542 / STRUCTURES	1,362,031	(43)	1,361,988		48,078	3.53%			1,410,066		19,773	23,517	1,453,356
437	543 / RESERVOIRS, DAMS & WATERWAYS	808,311		808,311		28,533	3.53%			836,844		10,774	12,813	860,431
438	544 / ELECTRIC PLANT													
439	LABOR	1,344,875		1,344,875		47,473	3.53%			1,392,348		40,211	47,823	1,480,382
440	OTHER	1,150,628	(29)	1,150,599		40,617	3.53%			1,191,216				1,191,216
441	TOTAL ACCOUNT 544	2,495,503	(29)	2,495,474		88,090	3.53%	0	0	2,583,564	0	40,211	47,823	2,671,598
442	545 / MISCELLANEOUS HYDRAULIC PLANT	3,135,803	(1,456)	3,134,347		110,643	3.53%			3,244,990		52,782	62,774	3,360,546
443	HYDRAULIC MAINTENANCE EXPENSES	9,686,802	(2,240)	9,684,562		341,865		0	0	10,026,427	0	169,819	201,967	10,398,213
444	TOTAL HYDRAULIC GENERATION EXPENSES	37,459,663	(4,830)	37,454,833		1,242,668		0	0	38,697,501	0	502,156	597,219	39,796,876

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2009

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
		2008	2008	2008	2008 to 2009 Forecast Adjustments					2009 Unadjusted	Normalizing	Annualizing	Known & Measurable	2009
	Description	Actuals	Adjustments	Base	3-Yr	O&M	Growth %	Fixed	Other	Forecast Year	Adjustments	Adjustments	Adjustments	Test Year
445	***TABLE 5-OPERATION & MAINTENANCE EXPENSES***													0
446	OTHER POWER GENERATION													
447	OPERATION													
448	546 / SUPERVISION & ENGINEERING	372,614		372,614		111,561	29.94%			484,175		9,225	10,971	504,371
449	547 / FUEL	17,387,510	(9,549,010)	7,838,500		0				7,838,500	271,300			8,109,800
450	548 / GENERATING EXPENSES													
451	LABOR	279,882		279,882		83,797	29.94%			363,679		8,368	9,952	381,999
452	OTHER	124,574		124,574		37,297	29.94%			161,871				161,871
453	TOTAL ACCOUNT 548	404,456		404,456		121,094	29.94%	0	0	525,550	0	8,368	9,952	543,870
454	549 / MISCELLANEOUS EXPENSES	530,176		530,176		158,735	29.94%			688,911		4,857	5,776	699,544
455	550 / RENTS	0		0		0				0				0
456	OTHER POWER OPER EXPENSES	18,694,756	(9,549,010)	9,145,746		391,390		0	0	9,537,136	271,300	22,450	26,699	9,857,585
457														
458	MAINTENANCE													
459	551 / SUPERVISION & ENGINEERING	213		213		64	29.94%			277				277
460	552 / STRUCTURES	162,376		162,376		48,615	29.94%			210,991		3,153	3,750	217,894
461	553 / GENERATING & ELECTRIC PLANT			0						0				
462	LABOR	108,823		108,823		32,573	29.94%			141,396		3,254	3,870	148,520
463	OTHER	89,448	(55)	89,393		26,773	29.94%			116,166				116,166
464	TOTAL ACCOUNT 553	198,271	(55)	198,216		59,346	29.94%	0	0	257,562	0	3,254	3,870	264,686
465	554 / MISCELLANEOUS EXPENSES	509,219		509,219		152,460	29.94%			661,679		6,038	7,181	674,898
466	OTHER POWER MAINT EXPENSES	870,079	(55)	870,024		260,485		0	0	1,130,509	0	12,445	14,801	1,157,755
467	TOTAL OTHER POWER GENERATION EXP	19,564,835	(9,549,065)	10,015,770		651,875		0	0	10,667,645	271,300	34,895	41,500	11,015,340
468				0						0				
469	OTHER POWER SUPPLY EXPENSE			0						0				
470	555.1 / PURCHASED POWER	185,251,733	(116,185,333)	69,066,400					797,462	69,863,862	10,373,900			80,237,762
471	555.2 / COGENERATION & SMALL POWER PROD			0						0				0
472	CAPACITY RELATED	2,815,124		2,815,124						2,815,124	**(2,815,124)**			0
473	ENERGY RELATED	43,070,440	17,388,606	60,459,046						60,459,046	3,199,954			63,659,000
474	TOTAL 555.2/CSPP	45,885,564	17,388,606	63,274,170						63,274,170	384,830			63,659,000
475	555/TOTAL	231,137,297	(98,796,727)	132,340,570				0	797,462	133,138,032	10,758,730	0		143,896,762
476	556 / LOAD CONTROL & DISPATCHING EXPENSES	77,979		77,979		23,347	29.94%			101,326				101,326
477	557 / OTHER EXPENSES	(44,906,304)	47,412,125	2,505,821		750,243	29.94%			3,256,064		57,219	68,050	3,381,333
478	TOTAL OTHER POWER SUPPLY EXPENSES	186,308,972	(51,384,602)	134,924,370		773,590		0	797,462	136,495,422	10,758,730	57,219	68,050	147,379,421
479				0						0				0
480	TOTAL PRODUCTION EXPENSES	420,196,322	(59,547,381)	360,648,941		4,318,528		0	797,462	365,764,931	13,133,930	601,671	715,571	380,216,103

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2009

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
		2008	2008	2008	2008 to 2009 Forecast Adjustments					2009 Unadjusted	Normalizing	Annualizing	Known & Measurable	2009
	Description	Actuals	Adjustments	Base	3-Yr	O&M	Growth %	Fixed	Other	Forecast Year	Adjustments	Adjustments	Adjustments	Test Year
481	***TABLE 5-OPERATION & MAINTENANCE EXPENSES***			0						0				0
482	TRANSMISSION EXPENSES			0						0				0
483	OPERATION			0						0				0
484	560 / SUPERVISION & ENGINEERING	2,404,396	(326)	2,404,070		(40,869)	-1.70%			2,363,201		46,604	55,427	2,465,232
485	561 / LOAD DISPATCHING	2,883,995	(36)	2,883,959		(49,027)	-1.70%			2,834,932		74,865	89,037	2,998,834
486	562 / STATION EXPENSES	1,805,492	(126)	1,805,366		(30,691)	-1.70%			1,774,675		37,446	44,535	1,856,656
487	563 / OVERHEAD LINE EXPENSES	735,577	(222)	735,355		(12,501)	-1.70%			722,854		11,571	13,761	748,186
488	565 / TRANSMISSION OF ELECTRICITY BY OTHERS	7,250,299		7,250,299						7,250,299		0	0	7,250,299
489	566 / MISCELLANEOUS EXPENSES	465,342	(8)	465,334		(7,911)	-1.70%			457,423		4,788	20,133	482,344
490	567 / RENTS	1,085,343	0	1,085,343		(18,451)	-1.70%			1,066,892		1	1	1,066,894
491	TOTAL TRANSMISSION OPERATION	16,630,444	(718)	16,629,726		(159,450)		0	0	16,470,276	0	175,275	222,894	16,868,445
492				0						0				0
493	MAINTENANCE			0						0				0
494	568 / SUPERVISION & ENGINEERING	431,690	(197)	431,493		(7,335)	-1.70%			424,158		2,089	2,484	428,731
495	569 / STRUCTURES	451,600		451,600		(7,677)	-1.70%			443,923		10,567	12,567	467,057
496	570 / STATION EQUIPMENT	2,706,579	(229)	2,706,350		(46,008)	-1.70%			2,660,342		44,691	53,151	2,758,184
497	571 / OVERHEAD LINES	3,367,619	(371)	3,367,248		(57,243)	-1.70%			3,310,005		29,256	34,794	3,374,055
498	573 / MISCELLANEOUS PLANT	272		272		(5)	-1.70%			267		0	0	267
499	TOTAL TRANSMISSION MAINTENANCE	6,957,760	(797)	6,956,963		(118,268)		0	0	6,838,695	0	86,603	102,996	7,028,294
500				0						0				0
501	TOTAL TRANSMISSION EXPENSES	23,588,204	(1,515)	23,586,689		(277,718)		0	0	23,308,971	0	261,878	325,890	23,896,739

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2009

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
		2008	2008	2008	2008 to 2009 Forecast Adjustments					2009 Unadjusted	Normalizing	Annualizing	Known & Measurable	2009
	Description	Actuals	Adjustments	Base	3-Yr	O&M	Growth %	Fixed	Other	Forecast Year	Adjustments	Adjustments	Adjustments	Test Year
502	***TABLE 5-OPERATION & MAINTENANCE EXPENSES***													0
503	DISTRIBUTION EXPENSES													0
504	OPERATION													0
505	580 / SUPERVISION & ENGINEERING	3,321,954	(2,083)	3,319,871		(171,637)	-5.17%			3,148,234		67,839	80,681	3,296,754
506	581 / LOAD DISPATCHING	3,110,301	(51)	3,110,250		(160,800)	-5.17%			2,949,450		78,675	93,569	3,121,694
507	582 / STATION EXPENSES	1,143,619	(509)	1,143,110		(59,099)	-5.17%			1,084,011		22,179	26,378	1,132,568
508	583 / OVERHEAD LINE EXPENSES	3,346,471	(788)	3,345,683		(172,972)	-5.17%			3,172,711		83,242	99,000	3,354,953
509	584 / UNDERGROUND LINE EXPENSES	2,034,228	(408)	2,033,820		(105,148)	-5.17%			1,928,672		25,811	30,698	1,985,181
510	585 / STREET LIGHTING & SIGNAL SYSTEMS	130,886	0	130,886		(6,767)	-5.17%			124,119		1,734	2,062	127,915
511	586 / METER EXPENSES	4,636,934	(856)	4,636,078		(239,685)	-5.17%			4,396,393		100,678	119,738	4,616,809
512	587 / CUSTOMER INSTALLATIONS EXPENSE	1,398,175	(292)	1,397,883		(72,271)	-5.17%			1,325,612		29,836	35,484	1,390,932
513	588 / MISCELLANEOUS EXPENSES	5,464,167	(1,194)	5,462,973		(282,436)	-5.17%			5,180,537		99,840	118,740	5,399,117
514	589 / RENTS	456,147	0	456,147		(23,583)	-5.17%			432,564		38	45	432,647
515	TOTAL DISTRIBUTION OPERATION	25,042,882	(6,181)	25,036,701		(1,294,398)		0	0	23,742,303	0	509,872	606,395	24,858,570
516														0
517	MAINTENANCE													0
518	590 / SUPERVISION & ENGINEERING	319,660	0	319,660		(16,526)	-5.17%			303,134		8,083	9,613	320,830
519	591 / STRUCTURES	2,323	0	2,323		(120)	-5.17%			2,203		0		2,203
520	592 / STATION EQUIPMENT	3,534,603	(1,657)	3,532,946		(182,653)	-5.17%			3,350,293		55,396	65,883	3,471,572
521	593 / OVERHEAD LINES	13,759,196	(6,548)	13,752,648		(711,012)	-5.17%			13,041,636		116,446	138,490	13,296,572
522	594 / UNDERGROUND LINES	1,235,321	(136)	1,235,185		(63,859)	-5.17%			1,171,326		23,270	27,675	1,222,271
523	595 / LINE TRANSFORMERS	445,190	0	445,190		(23,016)	-5.17%			422,174		787	936	423,897
524	596 / STREET LIGHTING & SIGNAL SYSTEMS	665,088	(50)	665,038		(34,382)	-5.17%			630,656		9,543	11,349	651,548
525	597 / METERS	862,862	(125)	862,737		(44,604)	-5.17%			818,133		17,188	20,442	855,763
526	598 / MISCELLANEOUS PLANT	354,999	(89)	354,910		(18,349)	-5.17%			336,561		5,547	6,597	348,705
527	TOTAL DISTRIBUTION MAINTENANCE	21,179,242	(8,605)	21,170,637		(1,094,521)		0	0	20,076,116	0	236,260	280,985	20,593,361
528	TOTAL DISTRIBUTION EXPENSES	46,222,124	(14,786)	46,207,338		(2,388,919)		0	0	43,818,419	0	746,132	887,380	45,451,931
529														0
530	CUSTOMER ACCOUNTING EXPENSES													0
531	901 / SUPERVISION	341,842	(84)	341,758		17,156	5.02%			358,914		8,479	10,084	377,477
532	902 / METER READING	5,752,965	(380)	5,752,585		288,780	5.02%			6,041,365		107,460	127,803	6,276,628
533	903 / CUSTOMER RECORDS & COLLECTIONS	11,773,960	0	11,773,960		591,053	5.02%			12,365,013		173,690	206,570	12,745,273
534	904 / UNCOLLECTIBLE ACCOUNTS	3,681,955	0	3,681,955		533	5.02%	1,328,654		5,011,142		0	0	5,011,142
535	905 / MISC EXPENSES	468	0	468		23	5.02%			491		0	0	491
536	TOTAL CUSTOMER ACCOUNTING EXPENSES	21,551,190	(464)	21,550,726		897,545		1,328,654	0	23,776,925	0	289,629	344,457	24,411,011
537														
538	CUSTOMER SERVICES & INFORMATION EXPENSES													
539	907 / SUPERVISION	299,410	(572)	298,838		15,002	5.02%			313,840		7,473	8,888	330,201
540	908 / CUSTOMER ASSISTANCE	27,674,741	(18,883,275)	8,791,466		441,332	5.02%			9,232,798		92,937	110,531	9,436,266
541														
542	909 / INFORMATION & INSTRUCTIONAL	0	0	0						0		0	0	0
543	910 / MISCELLANEOUS EXPENSES	860,302	(385)	859,917		43,168	5.02%			903,085		14,349	17,066	934,500
544	TOTAL CUST SERV & INFORMATN EXPENSES	28,834,453	(18,884,232)	9,950,221		499,502		0	0	10,449,723	0	114,759	136,485	10,700,967

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2009

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
		2008	2008	2008	2008 to 2009 Forecast Adjustments					2009 Unadjusted	Normalizing	Annualizing	Known & Measurable	2009
	Description	Actuals	Adjustments	Base	3-Yr	O&M	Growth %	Fixed	Other	Forecast Year	Adjustments	Adjustments	Adjustments	Test Year
545	***TABLE 5-OPERATION & MAINTENANCE EXPENSES***													
546	ADMINISTRATIVE & GENERAL EXPENSES													
547	920 / ADMINISTRATIVE & GENERAL SALARIES	57,537,274	(15,448,509)	42,088,765		(46,298)	-0.11%			42,042,467		7,819,478	1,240,336	51,102,281
548	921 / OFFICE SUPPLIES	14,791,346	(20,408)	14,770,938		(16,248)	-0.11%			14,754,690		6,317	7,513	14,768,520
549	922 / ADMIN & GENERAL EXPENSES TRANSFERRED-CR	(22,736,029)	0	(22,736,029)		25,010	-0.11%			(22,711,019)		0	0	(22,711,019)
550	923 / OUTSIDE SERVICES	13,597,223	0	13,597,223		(14,957)	-0.11%		11,115	13,593,381		0	0	13,593,381
551	924 / PROPERTY INSURANCE			0						0				0
552	PRODUCTION - STEAM	846,042		846,042				84,604		930,646		2,334		932,980
553	ALL RISK & MISCELLANEOUS	2,257,627		2,257,627				152,430		2,410,057		10,364	5,671	2,426,092
554	TOTAL ACCOUNT 924	3,103,669	0	3,103,669				237,034	0	3,340,703	0	12,698	5,671	3,359,072
555	925 / INJURIES & DAMAGES	7,548,140	0	7,548,140		(8,303)	-0.11%			7,539,837				7,539,837
556	926 / EMPLOYEE PENSIONS & BENEFITS	22,840,421	(2,852)	22,837,569		(25,121)	-0.11%			22,812,448		3,288	3,910	22,819,646
557	927 / FRANCHISE REQUIREMENTS	1,549	0	1,549		(2)	-0.11%			1,547				1,547
558	928 / REGULATORY COMMISSION EXPENSES			0						0				0
559	928.101 / FERC ADMIN ASSESS & SECURITIES			0						0				0
560	CAPACITY RELATED	1,902,421	0	1,902,421		14,268	-0.11%			1,930,957				1,930,957
561	ENERGY RELATED	830,277	0	830,277		6,227	-0.11%			842,731				842,731
562	928.101 / FERC ORDER 472	341,902	0	341,902		27,252	-0.11%			396,406				396,406
563	928.101 / FERC MISCELLANEOUS	1,176,210	0	1,176,210		(52,423)	-0.11%			1,071,364				1,071,364
564	928.102 FERC RATE CASE	32,513	0	32,513		(36)	-0.11%			32,477				32,477
565	928.104 / FERC OREGON HYDRO	158,506	0	158,506		(174)	-0.11%			158,332				158,332
566	928.202 / IDAHO PUC - RATE CASE	185,052	(44,969)	140,083		(154)	-0.11%			139,929				139,929
567	928.203 / IDAHO PUC - OTHER	13,565	0	13,565		(15)	-0.11%			13,550				13,550
568	928.301 / OREGON PUC - FILING FEES	0	0	0		0	-0.11%			0				0
569	928.302 / OREGON PUC - RATE CASE	203	0	203		0	-0.11%			203				203
570	928.303 / OREGON PUC - OTHER	191,548	0	191,548		(211)	-0.11%			191,337				191,337
571	IPC/PUC JSS TRUE-UP ADJ	0	0	0						0				0
572	TOTAL ACCOUNT 928	4,832,197	(44,969)	4,787,228		(5,266)		0	0	4,781,962				4,781,962
573	929 / DUPLICATE CHARGES	0	0	0						0				0
574	930.1 / GENERAL ADVERTISING	236,828	(236,828)	0		0	-0.11%			0				0
575	930.2 / MISCELLANEOUS EXPENSES	3,515,410	(196,541)	3,318,869		(3,651)	-0.11%			3,315,218		4,380	5,210	3,324,808
576	931 / RENTS	6,827	0	6,827		(8)	-0.11%			6,819				6,819
577	TOTAL ADM & GEN OPERATION	105,274,855	(15,950,107)	89,324,748		(94,844)	-0.11%	237,034	11,115	89,478,053	0	7,846,161	1,262,640	98,586,854
578	PLUS:			0						0				0
579	935 / GENERAL PLANT MAINTENANCE	4,149,186	(183)	4,149,003		(4,564)	-0.11%			4,144,439		29,100	34,609	4,208,148
580	416 / MERCHANDISING EXPENSE	0	1,203,883	1,203,883		0			(503,597)	700,286				700,286
581	TOTAL OPER & MAINT EXPENSES	649,816,334	(93,194,785)	556,621,549		2,949,530		1,565,688	304,980	561,441,747	13,133,930	9,889,330	3,707,032	588,172,039

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Jeannette Bowman
Summary of Adjustments - Depreciation & Amortization Expense

July 31, 2009

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2009

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
		2008	2008	2008	2008 to 2009 Forecast Adjustments					2009 Unadjusted	Normalizing	Annualizing	Known & Measurable	2009
	Description	Actuals	Adjustments	Base	3-Yr	O&M	Growth %	Fixed	Other	Forecast Year	Adjustments	Adjustments	Adjustments	Test Year
582	***TABLE 6-DEPRECIATION & AMORTIZATION EXPENSE***			0										
583				0										
584	DEPRECIATION EXPENSE			0										
585	310-316 / STEAM PRODUCTION	20,407,583		20,407,583				(2,403,107)		18,004,476	0	127,417	0	18,131,894
586	330-336 / HYDRAULIC PRODUCTION	13,871,109		13,871,109				1,213,559		15,084,668	0	132,762	0	15,217,429
587	340-346 / OTHER PRODUCTION	4,350,691		4,350,691				805,604		5,156,295	0	7,921	0	5,164,216
588	TOTAL PRODUCTION PLANT	38,629,383		38,629,383				(383,944)		38,245,439	0	268,100	0	38,513,540
589														
590	TRANSMISSION PLANT													
591	350 / LAND & LAND RIGHTS	508,132		508,132				(849,194)		(341,062)	0	0	0	(341,062)
592	352 / STRUCTURES & IMPROVEMENTS	588,321		588,321				133,751		722,073	0	21,770	0	743,843
593	353 / STATION EQUIPMENT	5,683,637		5,683,637				447,349		6,130,986	0	167,063	0	6,298,049
594	354 / TOWERS & FIXTURES	2,795,994		2,795,994				(53,334)		2,742,660	0	80,650	0	2,823,310
595	355 / POLES & FIXTURES	2,591,527		2,591,527				46,868		2,638,395	0	31,572	0	2,669,967
596	356 / OVERHEAD CONDUCTORS & DEVICES	2,801,960		2,801,960				121,075		2,923,035	0	45,279	0	2,968,314
597	359 / ROADS & TRAILS	3,288		3,288				(156)		3,133	0	0	0	3,133
598	TOTAL TRANSMISSION PLANT	14,972,859		14,972,859				(153,640)		14,819,219	0	346,335	0	15,165,554
599														
600	DISTRIBUTION PLANT													
601	360 / LAND & LAND RIGHTS	0		0				0		0	0	0	0	0
602	361 / STRUCTURES & IMPROVEMENTS	447,058		447,058				28,474		475,532	0	35,040	0	510,572
603	362 / STATION EQUIPMENT	2,737,211		2,737,211				523,991		3,261,201	0	141,173	0	3,402,374
604	364 / POLES, TOWERS & FIXTURES	7,245,763		7,245,763				(173,028)		7,072,735	0	181,692	0	7,254,427
605	365 / OVERHEAD CONDUCTORS & DEVICES	3,396,345		3,396,345				124,847		3,521,192	0	91,627	0	3,612,819
606	366 / UNDERGROUND CONDUIT	955,528		955,528				(13,271)		942,257	0	16,125	0	958,383
607	367 / UNDERGROUND CONDUCTORS & DEVICES	4,204,875		4,204,875				(608,057)		3,596,817	0	67,919	0	3,664,736
608	368 / LINE TRANSFORMERS	6,235,344		6,235,344				200,047		6,435,392	0	78,053	0	6,513,445
609	369 / SERVICES	1,878,105		1,878,105				(144,466)		1,733,639	0	14,594	0	1,748,233
610	370 / METERS	2,989,130		2,989,130				2,264,796		5,253,926	0	525,815	0	5,779,742
611	371 / INSTALLATIONS ON CUSTOMER PREMISES	(323)		(323)				27,119		26,797	0	259	0	27,055
612	373 / STREET LIGHTING SYSTEMS	209,009		209,009				(38,148)		170,861	0	636	0	171,498
613	TOTAL DISTRIBUTION PLANT	30,298,045		30,298,045				2,192,304		32,490,349	0	1,152,935	0	33,643,284

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2009

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
		2008	2008	2008	2008 to 2009 Forecast Adjustments					2009 Unadjusted	Normalizing	Annualizing	Known & Measurable	2009
	Description	Actuals	Adjustments	Base	3-Yr	O&M	Growth %	Fixed	Other	Forecast Year	Adjustments	Adjustments	Adjustments	Test Year
614	***TABLE 6-DEPRECIATION & AMORTIZATION EXPENSE***													
615														
616	GENERAL PLANT													
617	389 / LAND & LAND RIGHTS	0								0	0	0	0	0
618	390 / STRUCTURES & IMPROVEMENTS	1,667,624		1,667,624				103,013		1,770,637	0	45,672	0	1,816,309
619	391 / OFFICE FURNITURE & EQUIPMENT	7,827,244		7,827,244				1,054,946		8,882,189	0	582,539	0	9,464,729
620	392 / TRANSPORTATION EQUIPMENT	1,202		1,202				(1,202)		0	0	0	0	0
621	393 / STORES EQUIPMENT	74,803		74,803				(9,251)		65,552	0	3,046	0	68,597
622	394 / TOOLS, SHOP & GARAGE EQUIPMENT	317,240		317,240				(75,727)		241,512	0	7,914	0	249,427
623	395 / LABORATORY EQUIPMENT	649,294		649,294				(44,133)		605,162	0	23,094	0	628,256
624	396 / POWER OPERATED EQUIPMENT	1,990		1,990				(1,990)		0	0	0	0	0
625	397 / COMMUNICATIONS EQUIPMENT	2,153,257		2,153,257				(401,999)		1,751,258	0	126,786	0	1,878,045
626	398 / MISCELLANEOUS EQUIPMENT	340,942		340,942				97,271		438,213	0	31,918	0	470,131
627	TOTAL GENERAL PLANT	13,033,596		13,033,596				720,927		13,754,523	0	820,970	0	14,575,493
628														
629	TOTAL DEPRECIATION EXPENSE	96,933,883		96,933,883				2,375,647		99,309,530	0	2,588,340	0	101,897,870
630														
631	DEPRECIATION ON DISALLOWED COSTS	(296,299)		(296,299)				0		(296,299)	0	0	0	(296,299)
632	TOTAL DEPRECIATION EXPENSE	96,637,583		96,637,583				2,375,647		99,013,231	0	2,588,340	0	101,601,570
633														
634	AMORTIZATION EXPENSE													
635	INTANGIBLE PLANT	5,482,388		5,482,388				791,477		6,273,865	0	4,104	0	6,277,968
636	HYDRAULIC PRODUCTION	0		0					0	0	0	0	0	0
637	ADJUSTMENTS, GAINS & LOSSES	(538,470)	504,115	(34,355)				11,632		(22,723)	0	0	0	(22,723)
638	TOTAL AMORTIZATION EXPENSE	4,943,918	504,115	5,448,033				803,109	0	6,251,142	0	4,104	0	6,255,245
639														
640	TOTAL DEPRECIATION & AM0RTIZATION EXP	101,581,501	504,115	102,085,616				3,178,756	0	105,264,372	0	2,592,443	0	107,856,816

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Jeannette Bowman
Summary of Adjustments - Taxes Other than Income Taxes

July 31, 2009

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2009

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
		2008	2008	2008	2008 to 2009 Forecast Adjustments					2009 Unadjusted	Normalizing	Annualizing	Known & Measurable	2009
	Description	Actuals	Adjustments	Base	3-Yr	O&M	Growth %	Fixed	Other	Forecast Year	Adjustments	Adjustments	Adjustments	Test Year
641	***TABLE 7-TAXES OTHER THAN INCOME TAXES***													
642														
643	TAXES OTHER THAN INCOME													
644	FEDERAL TAXES													
645	FICA	11,476,651	(11,476,651)	0						0				0
646	FUTA	124,895	(124,895)	0						0				0
647	LESS PAYROLL DEDUCTION	(11,789,296)	11,789,296	0						0				0
648														
649	STATE TAXES													
650	AD VALOREM TAXES													
651	JIM BRIDGER STATION	972,234		972,234				*30,822*		1,003,056		18,387		1,021,443
652	VALMY	865,620		865,620				*30,822*		896,442		1,839		898,281
653	BOARDMAN	264,062		264,062				*30,822*		294,884				294,884
654	OTHER-PRODUCTION PLANT	3,537,048		3,537,048				*171,684*		3,708,732		1,777		3,710,509
655	OTHER-TRANSMISSION PLANT	2,951,256		2,951,256				*269,523*		3,220,779		18,057		3,238,836
656	OTHER-DISTRIBUTION PLANT	5,579,950		5,579,950				*439,940*		6,019,890		28,094		6,047,984
657	OTHER-GENERAL PLANT	960,955		960,955				*111,898*		1,072,853		4,421		1,077,274
658	SUB-TOTAL	15,131,125		15,131,125				*1,085,511*		16,216,636		72,575		16,289,211
659														
660	LICENSES - HYDRO PROJECTS	3,325		3,325	(34)		-1.11%			3,291				3,291
661														
662	REGULATORY COMMISSION FEES													
663	STATE OF IDAHO	1,728,039		1,728,039				*(34,561)*		1,693,478				1,693,478
664	STATE OF OREGON	119,843		119,843	9,815		8.19%			129,658				129,658
665	STATE OF NEVADA	0		0						0				0
666														
667	FRANCHISE TAXES													
668	STATE OF OREGON	541,650		541,650	19,879		3.67%			561,529				561,529
669	STATE OF NEVADA	0		0						0				0
670														
671	OTHER STATE TAXES													
672	UNEMPLOYMENT TAXES	187,750	(187,750)	0						0				0
673	HYDRO GENERATION KWH TAX	1,307,000		1,307,000						1,307,000	411,499			1,718,499
674	IRRIGATION-PIC	252,972		252,972						252,972	76,991			329,963
675														
676	TOTAL TAXES OTHER THAN INCOME	19,083,954	(0)	19,083,954	29,660	0		1,050,950	0	20,164,564	488,490	72,575	0	20,725,629

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Jeannette Bowman
Summary of Adjustments - Regulatory Debits and Credits

July 31, 2009

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2009

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
		2008	2008	2008	2008 to 2009 Forecast Adjustments					2009 Unadjusted	Normalizing	Annualizing	Known & Measurable	2009
	Description	Actuals	Adjustments	Base	3-Yr	O&M	Growth %	Fixed	Other	Forecast Year	Adjustments	Adjustments	Adjustments	Test Year
677	***TABLE 8-REGULATORY DEBITS & CREDITS***													
678	REGULATORY DEBITS/CREDITS													
679	STATE OF IDAHO	(3,781,013)	3,781,013	0						0				0
680	STATE OF OREGON	0		0						0				0
681														
682	TOTAL REGULATORY DEBITS/CREDITS	(3,781,013)	3,781,013	0				0		0				0
683														
684														

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Jeannette Bowman
Summary of Adjustments - Income Taxes

July 31, 2009

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2009

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
		2008	2008	2008	2008 to 2009 Forecast Adjustments					2009 Unadjusted	Normalizing	Annualizing	Known & Measurable	2009
	Description	Actuals	Adjustments	Base	3-Yr	O&M	Growth %	Fixed	Other	Forecast Year	Adjustments	Adjustments	Adjustments	Test Year
685	***TABLE 9-INCOME TAXES***													
686														
687	410/411 NET PROVISION FOR DEFERRED INCOME TAXES	40,319,488	0	40,319,488					(4,261,587)	36,057,901	0	0	0	36,057,901
688														
689	411.4 - INVESTMENT TAX CREDIT ADJUSTMENT	2,269,367	0	2,269,367					(3,226,936)	(957,569)	0	0	0	(957,569)
690														
691	SUMMARY OF INCOME TAXES													
692														
693	TOTAL FEDERAL INCOME TAX	(1,816,783)	(8,524,776)	(10,341,559)	(147,540)	(967,298)		(3,979,591)	8,803,339	(6,632,650)	14,744,010	(5,087,863)	(1,215,721)	1,807,776
694														
695	STATE INCOME TAX													
696	STATE OF IDAHO	(5,017,859)	(1,533,654)	(6,551,513)	(26,543)	(174,022)		(715,950)	3,891,808	(3,576,220)	2,652,528	(915,334)	(218,715)	(2,057,741)
697	STATE OF OREGON	55,778	(77,982)	(22,205)	(1,350)	(8,849)		(36,404)	34,427	(34,380)	134,874	(46,542)	(11,121)	42,831
698	OTHER STATES	31,435	(25,994)	5,441	(450)	(2,950)		(12,135)	59,996	49,902	44,958	(15,514)	(3,707)	75,639
699	TOTAL STATE INCOME TAXES	(4,930,646)	(1,637,630)	(6,568,277)	(28,343)	(185,820)		(764,489)	3,986,231	(3,560,698)	2,832,361	(977,391)	(233,543)	(1,939,271)

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2009

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
		2008	2008	2008	2008 to 2009 Forecast Adjustments					2009 Unadjusted	Normalizing	Annualizing	Known & Measurable	2009
	Description	Actuals	Adjustments	Base	3-Yr	O&M	Growth %	Fixed	Other	Forecast Year	Adjustments	Adjustments	Adjustments	Test Year
700	***TABLE 10-CALCULATION OF FEDERAL INCOME TAX***													0
701	OPERATING REVENUES	956,075,565	(104,682,635)	851,392,930	(420,226)	0		(6,339,356)	0	844,633,348	58,580,525	0	0	903,213,873
702										0				0
703	OPERATING EXPENSES									0				0
704	OPERATION & MAINTENANCE	649,816,334	(93,194,785)	556,621,549	0	2,949,530		1,565,688	304,980	561,441,747	13,133,930	9,889,330	3,707,032	588,172,039
705	DEPRECIATION EXPENSE	96,637,583	0	96,637,583	0	0		2,375,647	0	99,013,231	0	2,588,340	0	101,601,570
706	AMORTIZATION OF LIMITED TERM PLANT	4,943,918	504,115	5,448,033	0	0		803,109	0	6,251,142	0	4,104	0	6,255,245
707	TAXES OTHER THAN INCOME	19,083,954	0	19,083,954	29,660	0		1,050,950	0	20,164,564	488,490	72,575	0	20,725,629
708	REGULATORY DEBITS/CREDITS	(3,781,013)	3,781,013	0	0	0		0	0	0	0	0	0	0
709	TOTAL OPERATING EXPENSES	766,700,777	(88,909,657)	677,791,119	29,660	2,949,530		5,795,394	304,980	686,870,683	13,622,420	12,554,348	3,707,032	716,754,484
710														0
711	BOOK-TAX ADJUSTMENT	0	0	0						0	0	0	0	0
712														0
713	INCOME BEFORE TAX ADJUSTMENTS	189,374,788	(15,772,977)	173,601,811	(449,886)	(2,949,530)	0	(12,134,750)	(304,980)	157,762,665	44,958,105	(12,554,348)	(3,707,032)	186,459,389
714														
715	INCOME STATEMENT ADJUSTMENTS													
716	INTEREST EXPENSE / SYNCHRONIZATION	76,564,326	0	76,564,326						76,564,326	0	2,959,795	0	79,524,121
717														
718	NET OPERATING INCOME BEFORE TAXES	112,810,462	(15,772,977)	97,037,485	(449,886)	(2,949,530)	0	(12,134,750)	(304,980)	81,198,339	44,958,105	(15,514,143)	(3,707,032)	106,935,268
719														
720	ALLOWANCE FOR AFUDC	10,221,157	(10,221,157)	0					0	0	0	0	0	0
721	FEDERAL INCOME TAX ADJUSTMENTS	(58,706,182)	0	(58,706,182)					(45,003,282)	(103,709,464)	0	0	0	(103,709,464)
722														
723	NET OPER INCOME BEFORE STATE INCOME TAXES	64,325,437	(25,994,134)	38,331,303	(449,886)	(2,949,530)	0	(12,134,750)	(45,308,262)	(22,511,125)	44,958,105	(15,514,143)	(3,707,032)	3,225,804
724														
725	TOTAL STATE INCOME TAXES (ALLOWED)	(1,076,504)	(1,637,630)	(2,714,135)	(28,343)	(185,820)	0	(764,489)	132,089	(3,560,698)	2,832,361	(977,391)	(233,543)	(1,939,271)
726														
727	TOTAL FEDERAL TAXABLE INCOME	65,401,941	(24,356,504)	41,045,438	(421,543)	(2,763,710)	0	(11,370,261)	(45,440,351)	(18,950,427)	42,125,744	(14,536,752)	(3,473,489)	5,165,075
728														
729	FEDERAL TAX AT 35 PERCENT: ORDERED EFF. RATE	22,890,679	(8,524,776)	14,365,903	(147,540)	(967,298)	0	(3,979,591)	(15,904,123)	(6,632,650)	14,744,010	(5,087,863)	(1,215,721)	1,807,776
730	ADD: FIN 48 ADJUSTMENT	(12,762,395)	0	(12,762,395)	0	0	0	0	12,762,395	0	0	0	0	0
731	PRIOR YEARS' TAX ADJUSTMENT	(11,945,067)	0	(11,945,067)	0	0	0	0	11,945,067	0	0	0	0	0
732														
733	TOTAL FEDERAL INCOME TAX	(1,816,783)	(8,524,776)	(10,341,559)	(147,540)	(967,298)	0	(3,979,591)	8,803,339	(6,632,650)	14,744,010	(5,087,863)	(1,215,721)	1,807,776

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2009

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
		2008	2008	2008	2008 to 2009 Forecast Adjustments					2009 Unadjusted	Normalizing	Annualizing	Known & Measurable	2009
	Description	Actuals	Adjustments	Base	3-Yr	O&M	Growth %	Fixed	Other	Forecast Year	Adjustments	Adjustments	Adjustments	Test Year
734	***TABLE 11-OREGON STATE INCOME TAX***													
735														
736	NET OPERATING INCOME BEFORE TAXES - OREGON	112,810,462	(15,772,977)	97,037,485	(449,886)	(2,949,530)	0	(12,134,750)	(304,980)	81,198,339	44,958,105	(15,514,143)	(3,707,032)	106,935,268
737														
738	ALLOWANCE FOR AFUDC	10,221,157	(10,221,157)	0	0	0	0	0	0	0	0	0	0	0
739	STATE INCOME TAX ADJUSTMENTS	(58,706,182)	0	(58,706,182)					(45,003,282)	(103,709,464)	0	0	0	(103,709,464)
740	ADD: MFG DEDUCTION NOT ALLOWED	1,713,258	0	1,713,258					(91,192)	1,622,066	0	0	0	1,622,066
741														0
742	TOTAL STATE INCOME TAX ADJUSTMENTS - OREGON	(46,771,767)	(10,221,157)	(56,992,924)	0	0	0	0	(45,094,474)	(102,087,398)	0	0	0	(102,087,398)
743														0
744	INCOME SUBJECT TO OREGON TAX	66,038,695	(25,994,134)	40,044,561	(449,886)	(2,949,530)	0	(12,134,750)	(45,399,454)	(20,889,059)	44,958,105	(15,514,143)	(3,707,032)	4,847,870
745														0
746	IERCO TAXABLE INCOME	6,584,192	0	6,584,192					2,844,835	9,429,027	0	0	0	9,429,027
747														0
748	TOTAL STATE TAXABLE INCOME - OREGON	72,622,887	(25,994,134)	46,628,753	(449,886)	(2,949,530)	0	(12,134,750)	(42,554,619)	(11,460,032)	44,958,105	(15,514,143)	(3,707,032)	14,276,897
749														0
750	OREGON TAX AT 0.3 PERCENT: ORDERED EFF. RATE	217,869	(77,982)	139,886	(1,350)	(8,849)	0	(36,404)	(127,664)	(34,380)	134,874	(46,542)	(11,121)	42,831
751	LESS: INVESTMENT TAX CREDIT	0	0	0						0	0	0	0	0
752														
753	STATE INCOME TAX ALLOWED - OREGON	217,869	(77,982)	139,886	(1,350)	(8,849)	0	(36,404)	(127,664)	(34,380)	134,874	(46,542)	(11,121)	42,831
754	ADD: FIN 48 ADJUSTMENT	(33,922)	0	(33,922)					33,922	0	0	0	0	0
755	PRIOR YEARS' TAX ADJUSTMENT	(128,169)	0	(128,169)					128,169	0	0	0	0	0
756														0
757	STATE INCOME TAX PAID - OREGON	55,778	(77,982)	(22,205)	(1,350)	(8,849)	0	(36,404)	34,427	(34,380)	134,874	(46,542)	(11,121)	42,831
758														

IDAHO POWER COMPANY
DEVELOPMENT OF SYSTEM REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2009

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
		2008	2008	2008	2008 to 2009 Forecast Adjustments					2009 Unadjusted	Normalizing	Annualizing	Known & Measurable	2009
	Description	Actuals	Adjustments	Base	3-Yr	O&M	Growth %	Fixed	Other	Forecast Year	Adjustments	Adjustments	Adjustments	Test Year
759	***TABLE 12-IDAHO STATE INCOME TAX***													
760														0
761	NET OPERATING INCOME BEFORE TAXES - IDAHO	112,810,462	(15,772,977)	97,037,485	(449,886)	(2,949,530)	0	(12,134,750)	(304,980)	81,198,339	44,958,105	(15,514,143)	(3,707,032)	106,935,268
762														0
763	ALLOWANCE FOR AFUDC	10,221,157	(10,221,157)	0	0	0	0	0	0	0	0	0	0	0
764	TOTAL STATE INCOME TAX ADJUSTMENTS - IDAHO	(58,706,182)	0	(58,706,182)					(45,003,282)	(103,709,464)	0	0	0	(103,709,464)
765														0
766	INCOME SUBJECT TO IDAHO TAX	64,325,437	(25,994,134)	38,331,303	(449,886)	(2,949,530)	0	(12,134,750)	(45,308,262)	(22,511,125)	44,958,105	(15,514,143)	(3,707,032)	3,225,804
767														0
768	IERCO TAXABLE INCOME	6,584,192	0	6,584,192	0	0	0	0	2,844,835	9,429,027	0	0	0	9,429,027
769	BONUS DEPRECIATION ADJUSTMENT	(7,865,793)	0	(7,865,793)					897,158	(6,968,635)	0	0	0	(6,968,635)
770	TOTAL STATE TAXABLE INCOME - IDAHO	63,043,836	(25,994,134)	37,049,702	(449,886)	(2,949,530)	0	(12,134,750)	(41,566,269)	(20,050,733)	44,958,105	(15,514,143)	(3,707,032)	5,686,196
771														0
772	IDAHO TAX AT 5.9 PERCENT: ORDERED EFF. RATE	3,719,586	(1,533,654)	2,185,932	(26,543)	(174,022)	0	(715,950)	(2,452,410)	(1,182,993)	2,652,528	(915,334)	(218,715)	335,486
773	LESS: INVESTMENT TAX CREDIT	5,076,703	0	5,076,703					(2,683,476)	2,393,227	0	0	0	2,393,227
774														0
775	STATE INCOME TAX ALLOWED - IDAHO	(1,357,117)	(1,533,654)	(2,890,771)	(26,543)	(174,022)	0	(715,950)	231,066	(3,576,220)	2,652,528	(915,334)	(218,715)	(2,057,741)
776	ADD : FIN 48 ADJUSTMENT	(667,127)	0	(667,127)					667,127	0	0	0	0	0
777	PRIOR YEARS' TAX ADJUSTMENT	(2,993,615)	0	(2,993,615)					2,993,615	0	0	0	0	0
778	STATE INCOME TAX PAID - IDAHO	(5,017,859)	(1,533,654)	(6,551,513)	(26,543)	(174,022)	0	(715,950)	3,891,808	(3,576,220)	2,652,528	(915,334)	(218,715)	(2,057,741)
779														
780														
781	OTHER STATE INCOME TAX													
782	INCOME SUBJECT TO TAX	64,325,437	(25,994,134)	38,331,303	(449,886)	(2,949,530)	0	(12,134,750)	(45,308,262)	(22,511,125)	44,958,105	(15,514,143)	(3,707,032)	3,225,804
783														0
784	IERCO TAXABLE INCOME	6,584,192	0	6,584,192	0	0	0	0	2,844,835	9,429,027	0	0	0	9,429,027
785	BONUS DEPRECIATION ADJUSTMENT	(8,165,793)	0	(8,165,793)					71,150,389	62,984,596	0	0	0	62,984,596
786	TOTAL TAXABLE INCOME-OTHER STATES	62,743,836	(25,994,134)	36,749,702	(449,886)	(2,949,530)	0	(12,134,750)	28,686,962	49,902,498	44,958,105	(15,514,143)	(3,707,032)	75,639,427
787														0
788	OTHER TAX AT 0.1 PERCENT	62,744	(25,994)	36,750	(450)	(2,950)	0	(12,135)	28,687	49,902	44,958	(15,514)	(3,707)	75,639
789	ADD : FIN 48 ADJUSTMENT	(11,307)	0	(11,307)					11,307	0	0	0	0	0
790	PRIOR YEARS' TAX ADJUSTMENT	(20,002)	0	(20,002)					20,002	0	0	0	0	0
791	OTHER STATES' INCOME TAX PAID	31,435	(25,994)	5,441	(450)	(2,950)	0	(12,135)	59,996	49,902	44,958	(15,514)	(3,707)	75,639

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Jeannette Bowman
Jurisdictional Separation Study - Oregon Revenue Requirement

July 31, 2009

IDAHO POWER COMPANY
JURISDICTIONAL REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2009

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
4	***SUMMARY OF RESULTS***				
5	**RATE OF RETURN UNDER PRESENT RATES**				
6	TOTAL COMBINED RATE BASE		2,347,007,562	**110,780,820**	*2,236,226,742*
7					
8	OPERATING REVENUES				
9	FIRM JURISDICTIONAL SALES		744,087,565	**32,433,692**	*711,653,873*
10	SYSTEM OPPORTUNITY SALES		122,944,900	**5,707,695**	*117,237,205*
11	OTHER OPERATING REVENUES		36,181,407	**1,379,028**	*34,802,379*
12	TOTAL OPERATING REVENUES		903,213,872	**39,520,415**	*863,693,457*
13	OPERATING EXPENSES				
14	OPERATION & MAINTENANCE EXPENSES		588,172,039	**26,766,344**	*561,405,695*
15	DEPRECIATION EXPENSE		101,601,570	**5,490,638**	*96,110,932*
16	AMORTIZATION OF LIMITED TERM PLANT		6,255,245	**287,337**	*5,967,908*
17	TAXES OTHER THAN INCOME		20,725,629	**1,566,929**	*19,158,700*
18	REGULATORY DEBITS/CREDITS		0	**0**	*0*
19	PROVISION FOR DEFERRED INCOME TAXES		36,057,901	**558,244**	*35,499,657*
20	INVESTMENT TAX CREDIT ADJUSTMENT		(957,569)	**(14,825)**	*(942,744)*
21	FEDERAL INCOME TAXES		1,807,776	**27,988**	*1,779,788*
22	STATE INCOME TAXES		(1,939,271)	**(30,024)**	*(1,909,248)*
23	TOTAL OPERATING EXPENSES		751,723,320	**34,652,631**	*717,070,689*
24	OPERATING INCOME		151,490,552	**4,867,784**	*146,622,768*
25	ADD: IERCO OPERATING INCOME		6,128,867	**284,532**	*5,844,335*
26	CONSOLIDATED OPERATING INCOME		157,619,419	**5,152,315**	*152,467,103*
27	RATE OF RETURN UNDER PRESENT RATES		6.72%	**4.65%**	*6.82%*
28					
29	**DEVELOPMENT OF REVENUE REQUIREMENTS**				
30	RATE OF RETURN @ 11.25% ROE		8.680%	**8.680%**	
31					
32	RETURN		203,720,256	**9,615,775**	
33	EARNINGS DEFICIENCY		46,100,838	**4,463,460**	
34	ADD: CONSTRUCTION WORK IN PROGRESS (RELICENSING)	D10	0	**0**	
35	DEFICIENCY WITH CWIP		46,100,838	**4,463,460**	
36					
37	NET-TO-GROSS TAX MULTIPLIER		1.642	**1.642**	
38	**REVENUE DEFICIENCY**		75,697,575	**7,329,001**	
39					
40	FIRM JURISDICTIONAL REVENUES		748,726,689	**32,433,692**	
41	PERCENT INCREASE REQUIRED		10.11%	**22.60%**	
42					
43	SALES AND WHEELING REVENUES REQUIRED		824,424,264	**39,762,693**	

IDAHO POWER COMPANY
JURISDICTIONAL REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2009

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
44	***SUMMARY OF RESULTS***				
45	**DEVELOPMENT OF RATE BASE COMPONENTS**				
46	ELECTRIC PLANT IN SERVICE				
47	INTANGIBLE PLANT		52,307,548	**2,402,769**	*49,904,779*
48	PRODUCTION PLANT		1,749,880,662	**77,035,659**	*1,672,845,004*
49	TRANSMISSION PLANT		762,558,126	**29,937,279**	*732,620,847*
50	DISTRIBUTION PLANT		1,291,572,511	**72,939,416**	*1,218,633,095*
51	GENERAL PLANT		256,705,003	**12,140,974**	*244,564,029*
52	TOTAL ELECTRIC PLANT IN SERVICE		4,113,023,850	**194,456,096**	*3,918,567,753*
53	LESS: ACCUM PROVISION FOR DEPRECIATION		1,678,120,806	**80,531,452**	*1,597,589,354*
54	AMORT OF OTHER UTILITY PLANT		17,461,298	**802,092**	*16,659,206*
55	NET ELECTRIC PLANT IN SERVICE		2,417,441,746	**113,122,552**	*2,304,319,194*
56	LESS: CUSTOMER ADV FOR CONSTRUCTION		24,364,064	**33,084**	*24,330,980*
57	LESS: ACCUM DEFERRED INCOME TAXES		231,039,863	**10,927,130**	*220,112,733*
58	ADD : PLT HLD FOR FUTURE+ACQUIS ADJ		4,896,084	**210,997**	*4,685,087*
59	ADD : WORKING CAPITAL		89,797,820	**4,236,127**	*85,561,692*
60	ADD : CONSERVATION+OTHER DFRD PROG.		2,934,667	**116,559**	*2,818,108*
61	ADD : SUBSIDIARY RATE BASE		87,341,172	**4,054,798**	*83,286,374*
62	TOTAL COMBINED RATE BASE		2,347,007,562	**110,780,820**	*2,236,226,742*
63					
64	**DEVELOPMENT OF NET INCOME COMPONENTS**				
65	OPERATING REVENUES				
66	SALES REVENUES		867,032,465	**38,141,387**	*828,891,078*
67	OTHER OPERATING REVENUES		36,181,407	**1,379,028**	*34,802,379*
68	TOTAL OPERATING REVENUES		903,213,872	**39,520,415**	*863,693,457*
69	OPERATING EXPENSES				
70	OPERATION & MAINTENANCE EXPENSES		588,172,039	**26,766,344**	*561,405,695*
71	DEPRECIATION EXPENSE		101,601,570	**5,490,638**	*96,110,932*
72	AMORTIZATION OF LIMITED TERM PLANT		6,255,245	**287,337**	*5,967,908*
73	TAXES OTHER THAN INCOME		20,725,629	**1,566,929**	*19,158,700*
74	REGULATORY DEBITS/CREDITS		0	**0**	*0*
75	PROVISION FOR DEFERRED INCOME TAXES		36,057,901	**558,244**	*35,499,657*
76	INVESTMENT TAX CREDIT ADJUSTMENT		(957,569)	**(14,825)**	*(942,744)*
77	FEDERAL INCOME TAXES		1,807,776	**27,988**	*1,779,788*
78	STATE INCOME TAXES		(1,939,271)	**(30,024)**	*(1,909,248)*
79	TOTAL OPERATING EXPENSES		751,723,320	**34,652,631**	*717,070,689*
80	OPERATING INCOME		151,490,552	**4,867,784**	*146,622,768*
81	ADD: IERCO OPERATING INCOME	E10	6,128,867	**284,532**	*5,844,335*
82	CONSOLIDATED OPERATING INCOME		157,619,419	**5,152,315**	*152,467,103*

IDAHO POWER COMPANY
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	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
100	***TABLE 1-ELECTRIC PLANT IN SERVICE***				
101	INTANGIBLE PLANT				
102	301 - ORGANIZATION	P101P	55,947	**2,646**	*53,301*
103	302 - FRANCHISES & CONSENTS	D10	21,741,309	**957,126**	*20,784,183*
104	303 - MISCELLANEOUS	P101P	30,510,292	**1,442,997**	*29,067,295*
105					
106	TOTAL INTANGIBLE PLANT		52,307,548	**2,402,769**	*49,904,779*
107					
108	PRODUCTION PLANT				
109	310-316 / STEAM PRODUCTION	D10	894,454,269	**39,376,899**	*855,077,370*
110	330-336 / HYDRAULIC PRODUCTION	D10	690,230,520	**30,386,279**	*659,844,241*
111	340-346 / OTHER PRODUCTION	D10	165,195,873	**7,272,480**	*157,923,393*
112					
113	TOTAL PRODUCTION PLANT		1,749,880,662	**77,035,659**	*1,672,845,004*
114					
115	TRANSMISSION PLANT				
116	350 / LAND & LAND RIGHTS - SYSTEM SERVICE	D11	28,444,359	**1,121,221**	*27,323,138*
117	TRANSMISSION RETAIL	D12	252,850	**11,171**	*241,679*
118	DIRECT ASSIGNMENT	DA350	187,730	**1,144**	*186,586*
119	TOTAL ACCOUNT 350		28,884,939	**1,133,537**	*27,751,402*
120					
121	352 / STRUCTURES & IMPROVEMENTS - SYSTEM SERVICE	D11	40,690,247	**1,603,930**	*39,086,317*
122	TRANSMISSION RETAIL	D12	2,169,976	**95,875**	*2,074,101*
123	DIRECT ASSIGNMENT	DA352	230,972	**0**	*230,972*
124	TOTAL ACCOUNT 352		43,091,195	**1,699,805**	*41,391,390*
125					
126	353 / STATION EQUIPMENT - SYSTEM SERVICE	D11	280,443,912	**11,054,551**	*269,389,361*
127	TRANSMISSION RETAIL	D12	18,471,409	**816,109**	*17,655,300*
128	DIRECT ASSIGNMENT	DA353	2,390,275	**36,494**	*2,353,781*
129	TOTAL ACCOUNT 353		301,305,596	**11,907,155**	*289,398,441*
130					
131	354 / TOWERS & FIXTURES - SYSTEM SERVICE	D11	140,711,330	**5,546,566**	*135,164,764*
132	TRANSMISSION RETAIL	D12	0	**0**	*0*
133	DIRECT ASSIGNMENT	DA354	186,616	**0**	*186,616*
134	TOTAL ACCOUNT 354		140,897,946	**5,546,566**	*135,351,380*
135					
136	355 / POLES & FIXTURES - SYSTEM SERVICE	D11	91,125,472	**3,591,988**	*87,533,484*
137	TRANSMISSION RETAIL	D12	36,341	**1,606**	*34,735*
138	DIRECT ASSIGNMENT	DA355	2,995,391	**33,230**	*2,962,161*
139	TOTAL ACCOUNT 355		94,157,204	**3,626,824**	*90,530,380*
140					
141	356 / OVERHEAD CONDUCTORS & DEVICES - SYSTEM SERVICE	D11	151,591,044	**5,975,423**	*145,615,621*
142	TRANSMISSION RETAIL	D12	162,048	**7,160**	*154,888*
143	DIRECT ASSIGNMENT	DA356	2,149,803	**28,853**	*2,120,950*
144	TOTAL ACCOUNT 356		153,902,895	**6,011,436**	*147,891,459*
145					
146	359 / ROADS & TRAILS - SYSTEM SERVICE	D11	303,364	**11,958**	*291,406*
147	TRANSMISSION RETAIL	D12	0	**0**	*0*
148	DIRECT ASSIGNMENT	DA359	14,987	**0**	*14,987*
149	TOTAL ACCOUNT 359		318,351	**11,958**	*306,393*
150					
151	TOTAL TRANSMISSION PLANT		762,558,126	**29,937,279**	*732,620,847*

IDAHO POWER COMPANY
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	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
152	***TABLE 1-ELECTRIC PLANT IN SERVICE***				
153					
154	DISTRIBUTION PLANT				
155	360 / LAND & LAND RIGHTS - SYSTEM SERVICE	DA360S	4,662,695	**134,081**	*4,528,614*
156	DIRECT ASSIGNMENT	DA360	2,953	**0**	*2,953*
157	NET DISTRIBUTION PLANT		4,665,648	**134,081**	*4,531,567*
158	PLUS: ADJUSTMENT FOR CIAC	DA360C	89,389	**(278)**	*89,667*
159	NET DISTRIBUTION PLANT + CIAC		4,755,037	**133,803**	*4,621,234*
160					
161	361 / STRUCTURES & IMPROVEMENTS - SYSTEM SERVICE	DA361S	25,616,586	**700,513**	*24,916,073*
162	DIRECT ASSIGNMENT	DA361	271,060	**0**	*271,060*
163	NET DISTRIBUTION PLANT		25,887,646	**700,513**	*25,187,133*
164	PLUS: ADJUSTMENT FOR CIAC	DA361C	4,463,307	**30,275**	*4,433,032*
165	NET DISTRIBUTION PLANT + CIAC		30,350,953	**730,788**	*29,620,165*
166					
167	362 / STATION EQUIPMENT - SYSTEM SERVICE	DA362S	173,745,512	**5,168,491**	*168,577,021*
168	DIRECT ASSIGNMENT	DA362	1,575,234	**0**	*1,575,234*
169	NET DISTRIBUTION PLANT		175,320,746	**5,168,491**	*170,152,255*
170	PLUS: ADJUSTMENT FOR CIAC	DA362C	18,276,721	**92,041**	*18,184,680*
171	NET DISTRIBUTION PLANT + CIAC		193,597,467	**5,260,532**	*188,336,935*
172					
173	364 / POLES, TOWERS & FIXTURES	DA364	215,604,513	**16,211,702**	*199,392,812*
174	365 / OVERHEAD CONDUCTORS & DEVICES	DA365	119,672,203	**7,483,202**	*112,189,001*
175	366 / UNDERGROUND CONDUIT	DA366	48,290,046	**677,595**	*47,612,450*
176	367 / UNDERGROUND CONDUCTORS & DEVICES	DA367	187,190,957	**3,213,311**	*183,977,646*
177	368 / LINE TRANSFORMERS	DA368	386,306,786	**35,045,871**	*351,260,915*
178	369 / SERVICES	DA369	56,057,134	**2,911,197**	*53,145,937*
179	370 / METERS	DA370	65,830,908	**946,820**	*64,884,088*
180	371 / INSTALLATIONS ON CUSTOMER PREMISES	DA371	2,568,833	**235,990**	*2,332,843*
181	373 / STREET LIGHTING SYSTEMS	DA373	4,177,092	**210,642**	*3,966,450*
182					
183	TOTAL DISTRIBUTION PLANT (without CIAC)		1,291,572,511	**72,939,416**	*1,218,633,095*
184					
185	GENERAL PLANT				
186	389 / LAND & LAND RIGHTS	PTD	10,719,405	**506,979**	*10,212,426*
187	390 / STRUCTURES & IMPROVEMENTS	PTD	77,126,645	**3,647,738**	*73,478,907*
188	391 / OFFICE FURNITURE & EQUIPMENT	PTD	50,590,733	**2,392,711**	*48,198,023*
189	392 / TRANSPORTATION EQUIPMENT	PTD	58,064,811	**2,746,200**	*55,318,610*
190	393 / STORES EQUIPMENT	PTD	1,211,387	**57,293**	*1,154,094*
191	394 / TOOLS, SHOP & GARAGE EQUIPMENT	PTD	5,001,892	**236,567**	*4,765,326*
192	395 / LABORATORY EQUIPMENT	PTD	11,237,831	**531,498**	*10,706,333*
193	396 / POWER OPERATED EQUIPMENT	PTD	8,950,965	**423,340**	*8,527,625*
194	397 / COMMUNICATIONS EQUIPMENT	PTD	29,198,804	**1,380,970**	*27,817,834*
195	398 / MISCELLANEOUS EQUIPMENT	PTD	4,602,530	**217,679**	*4,384,851*
196					
197	TOTAL GENERAL PLANT		256,705,003	**12,140,974**	*244,564,029*
198					
199	TOTAL ELECTRIC PLANT IN SERVICE (without CIAC)		4,113,023,850	**194,456,096**	*3,918,567,753*

IDAHO POWER COMPANY
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	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
200	***TABLE 2-ACCUMULATED PROVISION FOR DEPRECIATION***				
201					
202	PRODUCTION PLANT				
203	310-316 / STEAM PRODUCTION	L 109	541,733,734	**23,848,949**	*517,884,785*
204	330-336 / HYDRAULIC PRODUCTION	L 110	317,716,072	**13,986,935**	*303,729,137*
205	340-346 / OTHER PRODUCTION	L 111	18,947,600	**834,137**	*18,113,463*
206	TOTAL PRODUCTION PLANT		878,397,406	**38,670,021**	*839,727,385*
207					
208	TRANSMISSION PLANT				
209	350 / LAND & LAND RIGHTS	L 119	4,851,695	**190,396**	*4,661,299*
210	352 / STRUCTURES & IMPROVEMENTS	L 124	19,883,088	**784,322**	*19,098,766*
211	353 / STATION EQUIPMENT	L 129	87,057,864	**3,440,399**	*83,617,465*
212	354 / TOWERS & FIXTURES	L 134	35,698,385	**1,405,297**	*34,293,088*
213	355 / POLES & FIXTURES	L 139	47,475,776	**1,828,711**	*45,647,065*
214	356 / OVERHEAD CONDUCTORS & DEVICES	L 144	48,794,565	**1,905,912**	*46,888,653*
215	359 / ROADS & TRAILS	L 149	252,010	**9,466**	*242,544*
216	TOTAL TRANSMISSION PLANT		244,013,383	**9,564,502**	*234,448,881*
217					
218	DISTRIBUTION PLANT				
219	360 / LAND & LAND RIGHTS	L 157	0	**0**	*0*
220	361 / STRUCTURES & IMPROVEMENTS	L 163	7,762,103	**210,040**	*7,552,063*
221	362 / STATION EQUIPMENT	L 169	41,534,744	**1,224,453**	*40,310,291*
222	364 / POLES, TOWERS & FIXTURES	L 173	102,231,985	**7,687,012**	*94,544,973*
223	365 / OVERHEAD CONDUCTORS & DEVICES	L 174	40,074,790	**2,505,910**	*37,568,880*
224	366 / UNDERGROUND CONDUIT	L 175	10,642,563	**149,334**	*10,493,229*
225	367 / UNDERGROUND CONDUCTORS & DEVICES	L 176	63,225,647	**1,085,329**	*62,140,318*
226	368 / LINE TRANSFORMERS	L 177	138,881,963	**12,599,415**	*126,282,548*
227	369 / SERVICES	L 178	34,610,977	**1,797,441**	*32,813,536*
228	370 / METERS	L 1004	13,918,914	**67,630**	*13,851,284*
229	371 / INSTALLATIONS ON CUSTOMER PREMISES	L 180	2,412,829	**221,659**	*2,191,170*
230	373 / STREET LIGHTING SYSTEMS	L 181	3,107,141	**156,687**	*2,950,454*
231	TOTAL DISTRIBUTION PLANT		458,403,656	**27,704,908**	*430,698,748*
232					

IDAHO POWER COMPANY
JURISDICTIONAL REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2009

	DESCRIPTION		ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
233	***TABLE 2-ACCUMULATED PROVISION FOR DEPRECIATION***					
234						
235	GENERAL PLANT					
236	389 / LAND & LAND RIGHTS	L 186		0	**0**	*0*
237	390 / STRUCTURES & IMPROVEMENTS	L 187		19,841,338	**938,405**	*18,902,933*
238	391 / OFFICE FURNITURE & EQUIPMENT	L 188		25,243,706	**1,193,912**	*24,049,794*
239	392 / TRANSPORTATION EQUIPMENT	L 189		18,322,947	**866,592**	*17,456,355*
240	393 / STORES EQUIPMENT	L 190		535,529	**25,328**	*510,201*
241	394 / TOOLS, SHOP & GARAGE EQUIPMENT	L 191		2,349,899	**111,139**	*2,238,759*
242	395 / LABORATORY EQUIPMENT	L 192		5,410,382	**255,886**	*5,154,496*
243	396 / POWER OPERATED EQUIPMENT	L 193		2,597,195	**122,835**	*2,474,359*
244	397 / COMMUNICATIONS EQUIPMENT	L 194		13,976,273	**661,014**	*13,315,259*
245	398 / MISCELLANEOUS EQUIPMENT	L 195		1,583,511	**74,893**	*1,508,618*
246	TOTAL GENERAL PLANT			89,860,777	**4,250,004**	*85,610,773*
247						
248	AMORTIZATION OF DISALLOWED COSTS	L 106		7,445,584	**342,016**	*7,103,568*
249						
250	TOTAL ACCUM PROVISION DEPRECIATION			1,678,120,806	**80,531,452**	*1,597,589,354*
251						
252	AMORTIZATION OF OTHER UTILITY PLANT					
253	INTANGIBLE PLANT	L 106		17,461,298	**802,092**	*16,659,206*
254	HYDRAULIC PRODUCTION	L 110		0	**0**	*0*
255						
256	TOTAL AMORT OF OTHER UTILITY PLANT			17,461,298	**802,092**	*16,659,206*
257						
258	TOTAL ACCUM PROVISION FOR DEPR					
259	& AMORTIZATION OF OTHER UTILITY PLANT			1,695,582,104	**81,333,544**	*1,614,248,560*
260						

IDAHO POWER COMPANY
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	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
261	***TABLE 3-ADDITIONS & DEDUCTIONS TO RATEBASE***				
262					
263	NET ELECTRIC PLANT IN SERVICE		2,417,441,746	**113,122,552**	*2,304,319,194*
264	LESS:				
265	252 CUSTOMER ADVANCES FOR CONSTRUCTION				
266	POWER SUPPLY	D10	0	**0**	*0*
267	OTHER	DA252	24,364,064	**33,084**	*24,330,980*
268	TOTAL CUSTOMER ADV FOR CONSTRUCTION		24,364,064	**33,084**	*24,330,980*
269					
270	ACCUMULATED DEFERRED INCOME TAXES				
271	190 / ACCUMULATED DEFERRED INCOME TAXES	P101P	(25,011,866)	**(1,182,947)**	*(23,828,919)*
272	281 / ACCELERATED AMORTIZATION	P101P	0	**0**	*0*
273	282 / OTHER PROPERTY	P101P	254,164,665	**12,020,827**	*242,143,838*
274	283 / OTHER	P101P	1,887,064	**89,250**	*1,797,814*
275	TOTAL ACCUM DEFERRED INCOME TAXES		231,039,863	**10,927,130**	*220,112,733*
276					
277	NET ELECTRIC PLANT IN SERVICE		2,162,037,819	**102,162,338**	*2,059,875,480*
278	ADD:				
279	WORKING CAPITAL				
280	151 / FUEL INVENTORY	E10	17,702,431	**821,832**	*16,880,599*
281	154 & 163 / PLANT MATERIALS & SUPPLIES				
282	PRODUCTION - GENERAL	L 113	13,667,291	**601,680**	*13,065,611*
283	TRANSMISSION - GENERAL	L 151	9,590,873	**376,528**	*9,214,345*
284	DISTRIBUTION - GENERAL	L 183+CIAC	20,320,626	**1,129,529**	*19,191,097*
285	OTHER - UNCLASSIFIED	L 199	4,989,717	**235,905**	*4,753,812*
286	TOTAL ACCOUNT 154 & 163		48,568,507	**2,343,642**	*46,224,865*
287	165 / PREPAID ITEMS				
288	AD VALOREM TAXES	L 658	0	**0**	*0*
289	OTHER PROD-RELATED PREPAYMENTS	D10	0	**0**	*0*
290	INSURANCE	L 113	0	**0**	*0*
291	PENSION EXPENSE	L 983	0	**0**	*0*
292	PREPAID RETIREE BENEFITS	L 983	0	**0**	*0*
293	MISCELLANEOUS PREPAYMENTS	P101P	0	**0**	*0*
294	TOTAL ACCOUNT 165		0	**0**	*0*
295	WORKING CASH ALLOWANCE	L 581	23,526,882	**1,070,654**	*22,456,228*
296					
297	TOTAL WORKING CAPITAL		89,797,820	**4,236,127**	*85,561,692*
298					
299	NET ELECTRIC PLANT IN SERVICE		2,251,835,638	**106,398,466**	*2,145,437,173*

IDAHO POWER COMPANY
JURISDICTIONAL REVENUE REQUIREMENT
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	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
300	***TABLE 3-ADDITIONS & DEDUCTIONS TO RATEBASE***				
301					
302	NET ELECTRIC PLANT IN SERVICE		2,251,835,638	**106,398,466**	*2,145,437,173*
303	ADD:				
304	105 / PLANT HELD FOR FUTURE USE				
305	HYDRAULIC PRODUCTION	L 110	0	**0**	*0*
306	TRANS LAND & LAND RIGHTS	L 119	524,719	**20,592**	*504,127*
307	TRANS STRUCTURES & IMPROVEMENTS	L 124	0	**0**	*0*
308	TRANS STATION EQUIPMENT	L 129	0	**0**	*0*
309	DIST LAND & LAND RIGHTS	L 159	1,053,999	**29,659**	*1,024,340*
310	DIST STRUCTURES & IMPROVEMENTS	L 165	0	**0**	*0*
311	GEN LAND & LAND RIGHTS	L 186	3,398,789	**160,747**	*3,238,042*
312	GEN STRUCTURES & IMPROVEMENTS	L 187	0	**0**	*0*
313	TRANSPORTATION EQUIPMENT	L 189	0	**0**	*0*
314	TOTAL PLANT HELD FOR FUTURE USE		4,977,507	**210,997**	*4,766,510*
315					
316	114/115 - PRAIRIE ACQUISITION ADJUSMENT (ACCOUNT 406)	CIDA	(81,423)	**0**	*(81,423)*
317					
318	DEFERRED PROGRAMS:				
319	182 / CONSERVATION PROGRAMS				
320	IDAHO DEFERRED CONSERVATION PROGRAMS	CIDA	1,621,331	**0**	*1,621,331*
321	OREGON DEFERRED CONSERVATION PROGRAMS	CODA	0	**0**	*0*
322	TOTAL CONSERVATION PROGRAMS		1,621,331	**0**	*1,621,331*
323	182 / MISC. OTHER REGULATORY ASSETS				
324	REORGANIZATION COSTS	LABOR	0	**0**	*0*
326	ZGA ARCHITECTS & PLANNERS	LABOR	7,395	**323**	*7,072*
327	PROFESSIONAL FEES	CIDA	0	**0**	*0*
328	INTERVENOR FUNDING	CIDA	5,731	**0**	*5,731*
329	GRID WEST - OPUC ORDER 06-483	CODA	72,193	**72,193**	*0*
330	GRID WEST - FERC	FERC	279,321	**0**	*279,321*
331	TOTAL OTHER REGULATORY ASSETS		364,640	**72,516**	*292,124*
332	186 / MISC. OTHER DEFERRED PROGRAMS				
325	AM. FALLS BOND REFINANCING	E10	948,696	**44,043**	*904,653*
333	TOTAL DEFERRED PROGRAMS		2,934,667	**116,559**	*2,818,108*
334					
335	DEVELOPMENT OF IERCO RATE BASE				
336	INVESTMENT IN IERCO	E10	62,425,002	**2,898,070**	*59,526,933*
337	PREPAID COAL ROYALTIES	E10	1,542,740	**71,621**	*1,471,119*
338	NOTES PAYABLE TO/RECEIVABLE FROM SUBSIDIARY	E10	23,373,430	**1,085,107**	*22,288,323*
339	TOTAL SUBSIDIARY RATE BASE		87,341,172	**4,054,798**	*83,286,374*
340					
341	TOTAL COMBINED RATE BASE		2,347,007,562	**110,780,820**	*2,236,226,742*

IDAHO POWER COMPANY
JURISDICTIONAL REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2009

DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
TABLE 4-OPERATING REVENUES				
FIRM ENERGY SALES				
440-448 / RETAIL	RETREV	741,988,731	**32,433,692**	*709,555,039*
440-REVENUE OFFSET FOR PLANT ADDITIONS	DAREV	0	**0**	*0*
447 / FIRM SALES FOR RESALE	RESREV	2,098,834	**0**	*2,098,834*
447 / SYSTEM OPPORTUNITY SALES	E10	122,944,900	**5,707,695**	*117,237,205*
TOTAL SALES OF ELECTRICITY		867,032,465	**38,141,387**	*828,891,078*
OTHER OPERATING REVENUES				
415 / MERCHANDISING REVENUES	D60	847,098	**36,605**	*810,493*
449 / OATT TARIFF REFUND				
NETWORK	DAFIRM	0	**0**	*0*
POINT-TO-POINT	D11	0	**0**	*0*
TOTAL ACCOUNT 449		0	0	0
451 / MISCELLANEOUS SERVICE REVENUES	DA451	3,018,555	**48,385**	*2,970,170*
454 / RENTS FROM ELECTRIC PROPERTY				
SUBSTATION EQUIPMENT	L 129	7,114,492	**281,154**	*6,833,338*
TRANSFORMER RENTALS	D11	17,330	**683**	*16,647*
LINE RENTALS	D11	2,039,614	**80,398**	*1,959,216*
COGENERATION	L 475	572,266	**26,567**	*545,699*
REAL ESTATE RENTS	L 197	340,570	**16,107**	*324,463*
DARK FIBER PROJECT	CIDA	447,047	**0**	*447,047*
POLE ATTACHMENTS	L 173	1,436,799	**108,036**	*1,328,763*
FACILITIES CHARGES	DA454	6,823,707	**439,234**	*6,384,473*
OTHER RENTALS	L 110	329,009	**14,484**	*314,525*
MISCELLANEOUS	DA454MISC	0	**0**	*0*
TOTAL ACCOUNT 454		19,120,834	**966,663**	*18,154,171*
456 / OTHER ELECTRIC REVENUES				
TRANSMISSION NETWORK SERVICES- FIRM DA	DAFIRM	4,639,124	**0**	*4,639,124*
TRANSMISSION POINT-TO-POINT	D11	8,003,143	**315,468**	*7,687,675*
PHOTOVOLTAIC STATION SERVICE	L 183+CIAC	11,601	**645**	*10,956*
ANTELOPE	L 151	73,824	**2,898**	*70,926*
ALTERNATIVE TRANSMISSION SERVICE CHARGE	L 151	0	**0**	*0*
SIERRA PACIFIC USAGE CHARGE	E10	103,087	**4,786**	*98,301*
STAND-BY SERVICE	DASTNBY	288,494	**0**	*288,494*
ENERGY EFFICIENCY RIDER	CIDA	0	**0**	*0*
MISCELLANEOUS	L 197	75,647	**3,578**	*72,069*
TOTAL ACCOUNT 456		13,194,920	**327,375**	*12,867,545*
TOTAL OTHER OPERATING REVENUES		36,181,407	**1,379,028**	34,802,379
TOTAL OPERATING REVENUES		903,213,872	**39,520,415**	*863,693,457*

IDAHO POWER COMPANY
JURISDICTIONAL REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2009

	DESCRIPTION		ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
388	***TABLE 5-OPERATION & MAINTENANCE EXPENSES***					
389	STEAM POWER GENERATION					
390	OPERATION					
391	500 / SUPERVISION & ENGINEERING	D10		1,726,522	**76,007**	*1,650,515*
392	501 / FUEL	E10		135,510,200	**6,291,037**	*129,219,163*
393	502 / STEAM EXPENSES					
394	LABOR	D10		2,435,969	**107,240**	*2,328,729*
395	OTHER	E10		5,212,182	**241,975**	*4,970,207*
396	TOTAL ACCOUNT 502			7,648,151	**349,214**	*7,298,937*
397	505 / ELECTRIC EXPENSES					
398	LABOR	D10		987,738	**43,484**	*944,254*
399	OTHER	E10		897,123	**41,649**	*855,474*
400	TOTAL ACCOUNT 505			1,884,861	**85,132**	*1,799,729*
401	506 / MISCELLANEOUS EXPENSES	D10		8,022,911	**353,196**	*7,669,715*
402	507 / RENTS	L 109		486,984	**21,439**	*465,545*
403	STEAM OPERATION EXPENSES			155,279,629	**7,176,025**	*148,103,604*
404						
405	MAINTENANCE					
406	510 / SUPERVISION & ENGINEERING	D10		2,662,214	**117,200**	*2,545,014*
407	511 / STRUCTURES	D10		413,387	**18,199**	*395,188*
408	512 / BOILER PLANT					
409	LABOR	D10		6,108,665	**268,924**	*5,839,741*
410	OTHER	E10		8,619,124	**400,141**	*8,218,983*
411	TOTAL ACCOUNT 512			14,727,789	**669,065**	*14,058,724*
412	513 / ELECTRIC PLANT					
413	LABOR	D10		1,856,398	**81,725**	*1,774,673*
414	OTHER	E10		2,603,034	**120,845**	*2,482,189*
415	TOTAL ACCOUNT 513			4,459,432	**202,570**	*4,256,862*
416	514 / MISCELLANEOUS STEAM PLANT	D10		4,482,015	**197,313**	*4,284,702*
417	STEAM MAINTENANCE EXPENSES			26,744,837	**1,204,347**	*25,540,490*
418	TOTAL STEAM GENERATION EXPENSES			182,024,466	**8,380,372**	*173,644,094*
419						

IDAHO POWER COMPANY
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	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
420	***TABLE 5-OPERATION & MAINTENANCE EXPENSES***				
421	HYDRAULIC POWER GENERATION				
422	OPERATION				
423	535 / SUPERVISION & ENGINEERING	L 836	6,060,332	**267,551**	*5,792,781*
424	536 / WATER FOR POWER	D10	7,559,899	**332,812**	*7,227,087*
425	537 / HYDRAULIC EXPENSES	D10	10,588,009	**466,120**	*10,121,889*
426	538 / ELECTRIC EXPENSES				
427	LABOR	D10	1,027,777	**45,246**	*982,531*
428	OTHER	E10	392,262	**18,211**	*374,051*
429	TOTAL ACCOUNT 538		1,420,039	**63,457**	*1,356,582*
430	539 / MISCELLANEOUS EXPENSES	D10	3,200,199	**140,884**	*3,059,315*
431	540 / RENTS	D10	570,185	**25,101**	*545,084*
432	HYDRAULIC OPERATION EXPENSES		29,398,663	**1,295,926**	*28,102,737*
433					
434	MAINTENANCE				
435	541 / SUPERVISION & ENGINEERING	L 847	2,052,282	**90,348**	*1,961,934*
436	542 / STRUCTURES	D10	1,453,356	**63,982**	*1,389,374*
437	543 / RESERVOIRS, DAMS & WATERWAYS	D10	860,431	**37,879**	*822,552*
438	544 / ELECTRIC PLANT				
439	LABOR	D10	1,480,382	**65,171**	*1,415,211*
440	OTHER	E10	1,191,216	**55,302**	*1,135,914*
441	TOTAL ACCOUNT 544		2,671,598	**120,473**	*2,551,125*
442	545 / MISCELLANEOUS HYDRAULIC PLANT	L 110	3,360,546	**147,943**	*3,212,603*
443	HYDRAULIC MAINTENANCE EXPENSES		10,398,213	**460,625**	*9,937,588*
444	TOTAL HYDRAULIC GENERATION EXPENSES		39,796,876	**1,756,551**	*38,040,325*

IDAHO POWER COMPANY
JURISDICTIONAL REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2009

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
445	***TABLE 5-OPERATION & MAINTENANCE EXPENSES***				
446	OTHER POWER GENERATION				
447	OPERATION				
448	546 / SUPERVISION & ENGINEERING	L 860	504,371	**22,204**	*482,167*
449	547 / FUEL	E10	8,109,800	**376,496**	*7,733,304*
450	548 / GENERATING EXPENSES				
451	LABOR	D10	381,999	**16,817**	*365,182*
452	OTHER	E10	161,872	**7,515**	*154,357*
453	TOTAL ACCOUNT 548		543,871	**24,332**	*519,539*
454	549 / MISCELLANEOUS EXPENSES	D10	699,544	**30,796**	*668,748*
455	550 / RENTS	D10	0	**0**	*0*
456	OTHER POWER OPER EXPENSES		9,857,586	**453,828**	*9,403,758*
457					
458	MAINTENANCE				
459	551 / SUPERVISION & ENGINEERING	L 870	277	**12**	*264*
460	552 / STRUCTURES	D10	217,894	**9,592**	*208,302*
461	553 / GENERATING & ELECTRIC PLANT				
462	LABOR	D10	148,520	**6,538**	*141,982*
463	OTHER	E10	116,166	**5,393**	*110,773*
464	TOTAL ACCOUNT 553		264,686	**11,931**	*252,755*
465	554 / MISCELLANEOUS EXPENSES	L 111	674,898	**29,711**	*645,186*
466	OTHER POWER MAINT EXPENSES		1,157,754	**51,247**	*1,106,507*
467	TOTAL OTHER POWER GENERATION EXP		11,015,340	**505,075**	*10,510,265*
468					
469	OTHER POWER SUPPLY EXPENSE				
470	555.1 / PURCHASED POWER	E10	80,237,762	**3,725,024**	*76,512,738*
471	555.2 / COGENERATION & SMALL POWER PROD				
472	CAPACITY RELATED	D10	0	**0**	*0*
473	ENERGY RELATED	E10	63,659,000	**2,955,358**	*60,703,642*
474	TOTAL 555.2/CSPP		63,659,000	**2,955,358**	*60,703,642*
475	555/TOTAL		143,896,762	**6,680,381**	*137,216,381*
476	556 / LOAD CONTROL & DISPATCHING EXPENSES	D10	101,326	**4,461**	*96,865*
477	557 / OTHER EXPENSES	D10	3,381,333	**148,858**	*3,232,475*
478	TOTAL OTHER POWER SUPPLY EXPENSES		147,379,421	**6,833,700**	*140,545,721*
479					
480	TOTAL PRODUCTION EXPENSES		380,216,103	**17,475,698**	*362,740,405*

IDAHO POWER COMPANY
JURISDICTIONAL REVENUE REQUIREMENT
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	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
481	***TABLE 5-OPERATION & MAINTENANCE EXPENSES***				
482	TRANSMISSION EXPENSES				
483	OPERATION				
484	560 / SUPERVISION & ENGINEERING	L 151	2,465,232	**96,783**	*2,368,449*
485	561 / LOAD DISPATCHING	D11	2,998,834	**118,208**	*2,880,626*
486	562 / STATION EXPENSES	L 129	1,856,656	**73,372**	*1,783,284*
487	563 / OVERHEAD LINE EXPENSES	L 134+139+144	748,186	**29,209**	*718,977*
488	565 / TRANSMISSION OF ELECTRICITY BY OTHERS	E10	7,250,299	**336,594**	*6,913,705*
489	566 / MISCELLANEOUS EXPENSES	L 151	482,344	**18,936**	*463,408*
490	567 / RENTS	L 151	1,066,894	**41,885**	*1,025,009*
491	TOTAL TRANSMISSION OPERATION		16,868,445	**714,987**	*16,153,458*
492					
493	MAINTENANCE				
494	568 / SUPERVISION & ENGINEERING	L 151	428,731	**16,832**	*411,899*
495	569 / STRUCTURES	L 124	467,057	**18,424**	*448,633*
496	570 / STATION EQUIPMENT	L 129	2,758,184	**108,999**	*2,649,185*
497	571 / OVERHEAD LINES	L 134+139+144	3,374,055	**131,722**	*3,242,333*
498	573 / MISCELLANEOUS PLANT	L 151	267	**10**	*257*
499	TOTAL TRANSMISSION MAINTENANCE		7,028,294	**275,988**	*6,752,306*
500					
501	TOTAL TRANSMISSION EXPENSES		23,896,739	**990,975**	*22,905,764*

IDAHO POWER COMPANY
JURISDICTIONAL REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2009

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
502	***TABLE 5-OPERATION & MAINTENANCE EXPENSES***				
503	DISTRIBUTION EXPENSES				
504	OPERATION				
505	580 / SUPERVISION & ENGINEERING	L 183	3,296,754	**186,179**	*3,110,575*
506	581 / LOAD DISPATCHING	D60	3,121,694	**134,897**	*2,986,797*
507	582 / STATION EXPENSES	L 171	1,132,568	**30,775**	*1,101,793*
508	583 / OVERHEAD LINE EXPENSES	L 173+174	3,354,953	**237,104**	*3,117,849*
509	584 / UNDERGROUND LINE EXPENSES	L 175+176	1,985,181	**32,802**	*1,952,379*
510	585 / STREET LIGHTING & SIGNAL SYSTEMS	L 181	127,915	**6,450**	*121,465*
511	586 / METER EXPENSES	L 179	4,616,809	**66,402**	*4,550,407*
512	587 / CUSTOMER INSTALLATIONS EXPENSE	L 180	1,390,932	**127,780**	*1,263,152*
513	588 / MISCELLANEOUS EXPENSES	L 183	5,399,117	**304,906**	*5,094,211*
514	589 / RENTS	L 183	432,647	**24,433**	*408,214*
515	TOTAL DISTRIBUTION OPERATION		24,858,570	**1,151,727**	*23,706,843*
516					
517	MAINTENANCE				
518	590 / SUPERVISION & ENGINEERING	L 183	320,830	**18,118**	*302,712*
519	591 / STRUCTURES	L 165	2,203	**53**	*2,150*
520	592 / STATION EQUIPMENT	L 171	3,471,572	**94,331**	*3,377,241*
521	593 / OVERHEAD LINES	L 173+174	13,296,572	**939,704**	*12,356,868*
522	594 / UNDERGROUND LINES	L 175+176	1,222,271	**20,196**	*1,202,075*
523	595 / LINE TRANSFORMERS	L 177	423,897	**38,456**	*385,441*
524	596 / STREET LIGHTING & SIGNAL SYSTEMS	L 181	651,548	**32,856**	*618,692*
525	597 / METERS	L 179	855,763	**12,308**	*843,455*
526	598 / MISCELLANEOUS PLANT	L 183	348,705	**19,693**	*329,012*
527	TOTAL DISTRIBUTION MAINTENANCE		20,593,361	**1,175,716**	*19,417,645*
528	TOTAL DISTRIBUTION EXPENSES		45,451,931	**2,327,443**	*43,124,488*
529					
530	CUSTOMER ACCOUNTING EXPENSES				
531	901 / SUPERVISION	L 940	377,477	**17,048**	*360,429*
532	902 / METER READING	CW902	6,276,628	**352,603**	*5,924,025*
533	903 / CUSTOMER RECORDS & COLLECTIONS	CW903	12,745,273	**481,926**	*12,263,347*
534	904 / UNCOLLECTIBLE ACCOUNTS	CW904	5,011,142	**217,540**	*4,793,602*
535	905 / MISC EXPENSES	L 532+533+534	491	**21**	*470*
536	TOTAL CUSTOMER ACCOUNTING EXPENSES		24,411,011	**1,069,139**	*23,341,872*
537					
538	CUSTOMER SERVICES & INFORMATION EXPENSES				
539	907 / SUPERVISION	L 948	330,201	**7,864**	*322,337*
540	908 / CUSTOMER ASSISTANCE	DA908	9,436,266	**224,725**	*9,211,541*
541					
542	909 / INFORMATION & INSTRUCTIONAL	DA909	0	**0**	*0*
543	910 / MISCELLANEOUS EXPENSES	L 540+542	934,500	**22,255**	*912,245*
544	TOTAL CUST SERV & INFORMATN EXPENSES		10,700,967	**254,844**	*10,446,123*

IDAHO POWER COMPANY
JURISDICTIONAL REVENUE REQUIREMENT
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	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
545	***TABLE 5-OPERATION & MAINTENANCE EXPENSES***				
546	ADMINISTRATIVE & GENERAL EXPENSES				
547	920 / ADMINISTRATIVE & GENERAL SALARIES	LABOR	51,102,281	**2,229,688**	*48,872,593*
548	921 / OFFICE SUPPLIES	LABOR	14,768,520	**644,378**	*14,124,142*
549	922 / ADMIN & GENERAL EXPENSES TRANSFERRED-CR	LABOR	(22,711,019)	**(990,924)**	*(21,720,095)*
550	923 / OUTSIDE SERVICES	LABOR	13,593,381	**593,105**	*13,000,276*
551	924 / PROPERTY INSURANCE				
552	PRODUCTION - STEAM	D10	932,980	**41,073**	*891,907*
553	ALL RISK & MISCELLANEOUS	P110P	2,426,092	**101,385**	*2,324,707*
554	TOTAL ACCOUNT 924		3,359,072	**142,458**	*3,216,614*
555	925 / INJURIES & DAMAGES	LABOR	7,539,837	**328,977**	*7,210,860*
556	926 / EMPLOYEE PENSIONS & BENEFITS	LABOR	22,819,646	**995,664**	*21,823,982*
557	927 / FRANCHISE REQUIREMENTS	CIDA	1,547	**0**	*1,547*
558	928 / REGULATORY COMMISSION EXPENSES				
559	928.101 / FERC ADMIN ASSESS & SECURITIES				
560	CAPACITY RELATED	D10	1,916,689	**84,379**	*1,832,310*
561	ENERGY RELATED	E10	836,504	**38,835**	*797,669*
562	928.101 / FERC ORDER 472	E99	369,154	**15,467**	*353,687*
563	928.101 / FERC MISCELLANIOUS	RESREV	1,123,787	**0**	*1,123,787*
564	928.102 FERC RATE CASE	RESREV	32,477	**0**	*32,477*
565	928.104 / FERC OREGON HYDRO	RESREV	158,332	**0**	*158,332*
566	928.202 / IDAHO PUC - RATE CASE	CIDA	139,929	**0**	*139,929*
567	928.203 / IDAHO PUC - OTHER	CIDA	13,550	**0**	*13,550*
568	928.301 / OREGON PUC - FILING FEES	CODA	0	**0**	*0*
569	928.302 / OREGON PUC - RATE CASE	CODA	203	**203**	*0*
570	928.303 / OREGON PUC - OTHER	CODA	191,337	**191,337**	*0*
571	IPC/PUC JSS TRUE-UP ADJ	PTD	0	**0**	*0*
572	TOTAL ACCOUNT 928		4,781,962	**330,221**	*4,451,741*
573	929 / DUPLICATE CHARGES	LABOR	0	**0**	*0*
574	930.1 / GENERAL ADVERTISING	LABOR	0	**0**	*0*
575	930.2 / MISCELLANEOUS EXPENSES	LABOR	3,324,808	**145,068**	*3,179,740*
576	931 / RENTS	L 197	6,819	**323**	*6,496*
577	TOTAL ADM & GEN OPERATION		98,586,854	**4,418,957**	*94,167,897*
578	PLUS:				
579	935 / GENERAL PLANT MAINTENANCE	L 197	4,208,148	**199,026**	*4,009,122*
580	416 / MERCHANDISING EXPENSE	D60	700,286	**30,261**	*670,025*
581	TOTAL OPER & MAINT EXPENSES		588,172,039	**26,766,344**	*561,405,695*

IDAHO POWER COMPANY
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	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
582	***TABLE 6-DEPRECIATION & AMORTIZATION EXPENSE***				
583					
584	DEPRECIATION EXPENSE				
585	310-316 / STEAM PRODUCTION	L 109	18,131,894	**798,227**	*17,333,667*
586	330-336 / HYDRAULIC PRODUCTION	L 110	15,217,429	**669,923**	*14,547,507*
587	340-346 / OTHER PRODUCTION	L 111	5,164,216	**227,346**	*4,936,870*
588	TOTAL PRODUCTION PLANT		38,513,540	**1,695,496**	*36,818,043*
589					
590	TRANSMISSION PLANT				
591	350 / LAND & LAND RIGHTS	L 119	(341,062)	**(13,384)**	*(327,677)*
592	352 / STRUCTURES & IMPROVEMENTS	L 124	743,843	**29,342**	*714,501*
593	353 / STATION EQUIPMENT	L 129	6,298,049	**248,890**	*6,049,159*
594	354 / TOWERS & FIXTURES	L 134	2,823,310	**111,142**	*2,712,168*
595	355 / POLES & FIXTURES	L 139	2,669,967	**102,844**	*2,567,124*
596	356 / OVERHEAD CONDUCTORS & DEVICES	L 144	2,968,314	**115,942**	*2,852,372*
597	359 / ROADS & TRAILS	L 149	3,133	**118**	*3,015*
598	TOTAL TRANSMISSION PLANT		15,165,554	**594,893**	*14,570,660*
599					
600	DISTRIBUTION PLANT				
601	360 / LAND & LAND RIGHTS	L 159	0	**0**	*0*
602	361 / STRUCTURES & IMPROVEMENTS	L 165	510,572	**12,294**	*498,279*
603	362 / STATION EQUIPMENT	L 171	3,402,374	**92,451**	*3,309,923*
604	364 / POLES, TOWERS & FIXTURES	L 173	7,254,427	**545,474**	*6,708,953*
605	365 / OVERHEAD CONDUCTORS & DEVICES	L 174	3,612,819	**225,913**	*3,386,906*
606	366 / UNDERGROUND CONDUIT	L 175	958,383	**13,448**	*944,935*
607	367 / UNDERGROUND CONDUCTORS & DEVICES	L 176	3,664,736	**62,909**	*3,601,827*
608	368 / LINE TRANSFORMERS	L 177	6,513,445	**590,902**	*5,922,543*
609	369 / SERVICES	L 178	1,748,233	**90,790**	*1,657,443*
610	370 / METERS	L 1005	5,779,742	**879,192**	*4,900,550*
611	371 / INSTALLATIONS ON CUSTOMER PREMISES	L 180	27,055	**2,485**	*24,570*
612	373 / STREET LIGHTING SYSTEMS	L 181	171,498	**8,648**	*162,849*
613	TOTAL DISTRIBUTION PLANT		33,643,283	**2,524,505**	*31,118,778*

IDAHO POWER COMPANY
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	DESCRIPTION		ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
614	***TABLE 6-DEPRECIATION & AMORTIZATION EXPENSE***					
615						
616	GENERAL PLANT					
617	389 / LAND & LAND RIGHTS	L 186		0	**0**	*0*
618	390 / STRUCTURES & IMPROVEMENTS	L 187		1,816,309	**85,903**	*1,730,406*
619	391 / OFFICE FURNITURE & EQUIPMENT	L 188		9,464,729	**447,638**	*9,017,090*
620	392 / TRANSPORTATION EQUIPMENT	L 189		0	**0**	*0*
621	393 / STORES EQUIPMENT	L 190		68,597	**3,244**	*65,353*
622	394 / TOOLS, SHOP & GARAGE EQUIPMENT	L 191		249,427	**11,797**	*237,630*
623	395 / LABORATORY EQUIPMENT	L 192		628,256	**29,714**	*598,542*
624	396 / POWER OPERATED EQUIPMENT	L 193		0	**0**	*0*
625	397 / COMMUNICATIONS EQUIPMENT	L 194		1,878,045	**88,823**	*1,789,222*
626	398 / MISCELLANEOUS EQUIPMENT	L 195		470,131	**22,235**	*447,896*
627	TOTAL GENERAL PLANT			14,575,493	**689,354**	*13,886,139*
628						
629	TOTAL DEPRECIATION EXPENSE			101,897,870	**5,504,249**	*96,393,621*
630						
631	DEPRECIATION ON DISALLOWED COSTS	L 106		(296,299)	**(13,611)**	*(282,689)*
632	TOTAL DEPRECIATION EXPENSE			101,601,570	**5,490,638**	*96,110,932*
633						
634	AMORTIZATION EXPENSE					
635	INTANGIBLE PLANT	L 106		6,277,968	**288,381**	*5,989,587*
636	HYDRAULIC PRODUCTION	L 110		0	**0**	*0*
637	ADJUSTMENTS, GAINS & LOSSES	L 106		(22,723)	**(1,044)**	*(21,679)*
638	TOTAL AMORTIZATION EXPENSE			6,255,245	**287,337**	*5,967,908*
639						
640	TOTAL DEPRECIATION & AM0RTIZATION EXP			107,856,815	**5,777,976**	*102,078,840*

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DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
TABLE 7-TAXES OTHER THAN INCOME TAXES				
TAXES OTHER THAN INCOME				
FEDERAL TAXES				
FICA	LABOR	0	**0**	*0*
FUTA	LABOR	0	**0**	*0*
LESS PAYROLL DEDUCTION	LABOR	0	**0**	*0*
STATE TAXES				
AD VALOREM TAXES				
JIM BRIDGER STATION	L 109	1,021,443	**44,967**	*976,476*
VALMY	L 109	898,281	**39,545**	*858,736*
BOARDMAN	L 109	294,884	**12,982**	*281,902*
OTHER-PRODUCTION PLANT	L 113	3,710,509	**163,349**	*3,547,160*
OTHER-TRANSMISSION PLANT	L 151	3,238,836	**127,154**	*3,111,682*
OTHER-DISTRIBUTION PLANT	L 183	6,047,984	**341,550**	*5,706,434*
OTHER-GENERAL PLANT	L 197	1,077,274	**50,950**	*1,026,324*
SUB-TOTAL		16,289,211	**780,497**	*15,508,714*
LICENSES - HYDRO PROJECTS	L 110	3,291	**145**	*3,146*
REGULATORY COMMISSION FEES				
STATE OF IDAHO	CIDA	1,693,478	**0**	*1,693,478*
STATE OF OREGON	CODA	129,658	**129,658**	*0*
STATE OF NEVADA	FERC	0	**0**	*0*
FRANCHISE TAXES				
STATE OF OREGON	CODA	561,529	**561,529**	*0*
STATE OF NEVADA	FERC	0	**0**	*0*
OTHER STATE TAXES				
UNEMPLOYMENT TAXES	LABOR	0	**0**	*0*
HYDRO GENERATION KWH TAX	E10	1,718,499	**79,781**	*1,638,718*
IRRIGATION-PIC	E10	329,963	**15,318**	*314,645*
TOTAL TAXES OTHER THAN INCOME		20,725,629	**1,566,929**	*19,158,700*

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	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
677	***TABLE 8-REGULATORY DEBITS & CREDITS***				
678	REGULATORY DEBITS/CREDITS				
679	STATE OF IDAHO	CIDA	0	**0**	*0*
680	STATE OF OREGON	CODA	0	**0**	*0*
681					
682	TOTAL REGULATORY DEBITS/CREDITS		0	**0**	*0*
683					
684					

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	DESCRIPTION		ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
685	***TABLE 9-INCOME TAXES***					
686						
687	410/411 NET PROVISION FOR DEFERRED INCOME TAXES	L 718		36,057,901	**558,244**	*35,499,657*
688						
689	411.4 - INVESTMENT TAX CREDIT ADJUSTMENT	L 718		(957,569)	**(14,825)**	*(942,744)*
690						
691	SUMMARY OF INCOME TAXES					
692						
693	TOTAL FEDERAL INCOME TAX			1,807,776	**27,988**	*1,779,788*
694						
695	STATE INCOME TAX					
696	STATE OF IDAHO			(2,057,741)	**(31,858)**	*(2,025,884)*
697	STATE OF OREGON			42,831	**663**	*42,168*
698	OTHER STATES			75,639	**1,171**	*74,468*
699	TOTAL STATE INCOME TAXES			(1,939,271)	**(30,024)**	*(1,909,248)*

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	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
700	***TABLE 10-CALCULATION OF FEDERAL INCOME TAX***				
701	OPERATING REVENUES		903,213,872	**39,520,415**	*863,693,457*
702					
703	OPERATING EXPENSES				
704	OPERATION & MAINTENANCE		588,172,039	**26,766,344**	*561,405,695*
705	DEPRECIATION EXPENSE		101,601,570	**5,490,638**	*96,110,932*
706	AMORTIZATION OF LIMITED TERM PLANT		6,255,245	**287,337**	*5,967,908*
707	TAXES OTHER THAN INCOME		20,725,629	**1,566,929**	*19,158,700*
708	REGULATORY DEBITS/CREDITS		0	**0**	*0*
709	TOTAL OPERATING EXPENSES		716,754,483	**34,111,248**	*682,643,236*
710					
711	BOOK-TAX ADJUSTMENT	L 709	0	**0**	*0*
712					
713	INCOME BEFORE TAX ADJUSTMENTS		186,459,389	**5,409,167**	*181,050,221*
714					
715	INCOME STATEMENT ADJUSTMENTS				
716	INTEREST EXPENSE SYNCHRONIZATION	L 341	79,524,121	**3,753,608**	*75,770,513*
717					
718	NET OPERATING INCOME BEFORE TAXES		106,935,268	**1,655,559**	*105,279,709*
719					
720	ALLOWANCE FOR AFUDC	L 718	0	**0**	*0*
721	FEDERAL INCOME TAX ADJUSTMENTS	L 718	(103,709,464)	**(1,605,617)**	*(102,103,847)*
722					
723	NET OPER INCOME BEFORE STATE INCOME TAXES		3,225,804	**49,942**	*3,175,862*
724					
725	TOTAL STATE INCOME TAXES (ALLOWED)	L 753+754+775+776+788+789	(1,939,271)	**(30,024)**	*(1,909,248)*
726					
727	TOTAL FEDERAL TAXABLE INCOME		5,165,075	**79,965**	*5,085,110*
728					
729	FEDERAL TAX AT 35 PERCENT: ORDERED EFF. RATE	**@ 35.00%**	1,807,776	**27,988**	***1,779,788***
730	ADD : CURRENT YEAR'S TAX DEFICIENCIES	L 729	0	**0**	*0*
731	PRIOR YEARS' TAX ADJUSTMENT	L 729	0	**0**	*0*
732					
733	TOTAL FEDERAL INCOME TAX		1,807,776	**27,988**	*1,779,788*

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	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
734	***TABLE 11-OREGON STATE INCOME TAX***				
735					
736	NET OPERATING INCOME BEFORE TAXES - OREGON	L 718	106,935,268	**1,655,559**	*105,279,709*
737					
738	ALLOWANCE FOR AFUDC	L 736	0	**0**	*0*
739	STATE INCOME TAX ADJUSTMENTS	L 736	(103,709,464)	**(1,605,617)**	*(102,103,847)*
740	ADD: MFG DEDUCTION NOT ALLOWED	L 736	1,622,066	**25,113**	*1,596,953*
741					
742	TOTAL STATE INCOME TAX ADJUSTMENTS - OREGON		(102,087,398)	**(1,580,505)**	*(100,506,893)*
743					
744	INCOME SUBJECT TO OREGON TAX		4,847,870	**75,054**	*4,772,816*
745					
746	IERCO TAXABLE INCOME	L 744	9,429,027	**145,979**	*9,283,048*
747					
748	TOTAL STATE TAXABLE INCOME - OREGON		14,276,897	**221,033**	*14,055,863*
749					
750	OREGON TAX AT 0.3 PERCENT: ORDERED EFF. RATE	**@ 0.30%**	42,831	**663**	*42,168*
751	LESS: INVESTMENT TAX CREDIT	L 750	0	**0**	*0*
752					
753	STATE INCOME TAX ALLOWED - OREGON		42,831	**663**	*42,168*
754	ADD: CURRENT YEAR'S TAX DEFICIENCY	L 750	0	**0**	*0*
755	PRIOR YEARS' TAX ADJUSTMENT	L 750	0	**0**	*0*
756					
757	STATE INCOME TAX PAID - OREGON		42,831	**663**	*42,168*
758					

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	DESCRIPTION		ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
759	***TABLE 12-IDAHO STATE INCOME TAX***					
760						
761	NET OPERATING INCOME BEFORE TAXES - IDAHO	L 718		106,935,268	**1,655,559**	*105,279,709*
762						
763	ALLOWANCE FOR AFUDC	L 761		0	**0**	*0*
764	TOTAL STATE INCOME TAX ADJUSTMENTS - IDAHO	L 761		(103,709,464)	**(1,605,617)**	*(102,103,847)*
765						
766	INCOME SUBJECT TO IDAHO TAX			3,225,804	**49,942**	*3,175,862*
767						
768	IERCO TAXABLE INCOME	L 766		9,429,027	**145,979**	*9,283,048*
769	BONUS DEPRECIATION ADJUSTMENT	L 766		(6,968,635)	**(107,888)**	*(6,860,747)*
770	TOTAL STATE TAXABLE INCOME - IDAHO			5,686,196	**88,033**	*5,598,163*
771						
772	IDAHO TAX AT 5.9 PERCENT: ORDERED EFF. RATE	**@ 5.90%**		335,486	**5,194**	***330,292***
773	LESS: INVESTMENT TAX CREDIT	L 772		2,393,227	**37,052**	*2,356,175*
774						
775	STATE INCOME TAX ALLOWED - IDAHO			(2,057,741)	**(31,858)**	*(2,025,884)*
776	ADD : CURRENT YEAR'S TAX DEFICIENCY	L 772		0	**0**	*0*
777	PRIOR YEARS' TAX ADJUSTMENT	L 772		0	**0**	*0*
778	STATE INCOME TAX PAID - IDAHO			(2,057,741)	**(31,858)**	*(2,025,884)*
779						
780						
781	OTHER STATE INCOME TAX					
782	INCOME SUBJECT TO TAX			3,225,804	**49,942**	*3,175,862*
783						
784	IERCO TAXABLE INCOME	L 782		9,429,027	**145,979**	*9,283,048*
785	BONUS DEPRECIATION ADJUSTMENT	L 782		62,984,596	**975,120**	*62,009,476*
786	TOTAL TAXABLE INCOME-OTHER STATES			75,639,427	**1,171,040**	*74,468,386*
787						
788	OTHER TAX AT 0.1 PERCENT			75,639	**1,171**	*74,468*
789	ADD : CURRENT YEAR'S TAX DEFICIENCY	L 778		0	**0**	*0*
790	PRIOR YEARS' TAX ADJUSTMENT	L 778		0	**0**	*0*
791	OTHER STATES' INCOME TAX PAID			75,639	**1,171**	*74,468*

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	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
792	***TABLE 13-DEVELOPMENT OF LABOR RELATED ALLOCATOR***				
793	STEAM POWER GENERATION				
794	OPERATION				
795	500 / SUPERVISION & ENGINEERING	L 796-806	237,227	**10,444**	*226,783*
796	501 / FUEL	D10	0	**0**	*0*
797	502 / STEAM EXPENSES				
798	LABOR	D10	0	**0**	*0*
799	OTHER	D10	0	**0**	*0*
800	TOTAL ACCOUNT 502		0	**0**	*0*
801	505 / ELECTRIC EXPENSES				
802	LABOR	D10	0	**0**	*0*
803	OTHER	D10	0	**0**	*0*
804	TOTAL ACCOUNT 505		0	**0**	*0*
805	506 / MISCELLANEOUS EXPENSES	D10	10,303	**454**	*9,849*
806	507 / RENTS	D10	0	**0**	*0*
807	STEAM OPERATION EXPENSES		247,530	**10,897**	*236,633*
808					
809	MAINTENANCE				
810	510 / SUPERVISION & ENGINEERING	L 811-820	0	**0**	*0*
811	511 / STRUCTURES	D10	0	**0**	*0*
812	512 / BOILER PLANT				
813	LABOR	D10	0	**0**	*0*
814	OTHER	D10	0	**0**	*0*
815	TOTAL ACCOUNT 512		0	**0**	*0*
816	513 / ELECTRIC PLANT				
817	LABOR	D10	0	**0**	*0*
818	OTHER	D10	0	**0**	*0*
819	TOTAL ACCOUNT 513		0	**0**	*0*
820	514 / MISCELLANEOUS STEAM PLANT	D10	0	**0**	*0*
821	STEAM MAINTENANCE EXPENSES		0	**0**	*0*
822	TOTAL STEAM GENERATION EXPENSES		247,530	**10,897**	*236,633*
823					

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	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
824	***TABLE 13-DEVELOPMENT OF LABOR RELATED ALLOCATOR***				
825	HYDRAULIC POWER GENERATION				
826	OPERATION				
827	535 / SUPERVISION & ENGINEERING	L 828-835	3,976,587	**175,558**	*3,801,029*
828	536 / WATER FOR POWER	E10	370,419	**17,197**	*353,222*
829	537 / HYDRAULIC EXPENSES	D10	3,954,779	**174,103**	*3,780,676*
830	538 / ELECTRIC EXPENSES				
831	LABOR	D10	933,699	**41,105**	*892,594*
832	OTHER	D10	0	**0**	*0*
833	TOTAL ACCOUNT 538		933,699	**41,105**	*892,594*
834	539 / MISCELLANEOUS EXPENSES	D10	1,879,749	**82,753**	*1,796,996*
835	540 / RENTS	D10	0	**0**	*0*
836	HYDRAULIC OPERATION EXPENSES		11,115,233	**490,715**	*10,624,518*
837					
838	MAINTENANCE				
839	541 / SUPERVISION & ENGINEERING	L 840-846	1,547,818	**68,140**	*1,479,678*
840	542 / STRUCTURES	D10	661,332	**29,114**	*632,218*
841	543 / RESERVOIRS, DAMS & WATERWAYS	D10	360,338	**15,863**	*344,475*
842	544 / ELECTRIC PLANT				
843	LABOR	D10	1,344,875	**59,206**	*1,285,669*
844	OTHER	D10	0	**0**	*0*
845	TOTAL ACCOUNT 544		1,344,875	**59,206**	*1,285,669*
846	545 / MISCELLANEOUS HYDRAULIC PLANT	D10	1,765,317	**77,715**	*1,687,602*
847	HYDRAULIC MAINTENANCE EXPENSES		5,679,680	**250,039**	*5,429,641*
848	TOTAL HYDRAULIC GENERATION EXPENSES		16,794,913	**740,754**	*16,054,159*

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	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
849	***TABLE 13-DEVELOPMENT OF LABOR RELATED ALLOCATOR***				
850	OTHER POWER GENERATION				
851	OPERATION				
852	546 / SUPERVISION & ENGINEERING	L 853-859	308,532	**13,583**	*294,949*
853	547 / FUEL	E10	0	**0**	*0*
854	548 / GENERATING EXPENSES				
855	LABOR	D10	279,882	**12,321**	*267,561*
856	OTHER	D10	0	**0**	*0*
857	TOTAL ACCOUNT 548		279,882	**12,321**	*267,561*
858	549 / MISCELLANEOUS EXPENSES	D10	162,436	**7,151**	*155,285*
859	550 / RENTS	D10	0	**0**	*0*
860	OTHER POWER OPER EXPENSES		750,850	**33,055**	*717,795*
861					
862	MAINTENANCE				
863	551 / SUPERVISION & ENGINEERING	L 864-869	0	**0**	*0*
864	552 / STRUCTURES	D10	105,458	**4,643**	*100,815*
865	553 / GENERATING & ELECTRIC PLANT				
866	LABOR	D10	108,823	**4,791**	*104,032*
867	OTHER	D10	0	**0**	*0*
868	TOTAL ACCOUNT 553		108,823	**4,791**	*104,032*
869	554 / MISCELLANEOUS EXPENSES	D10	201,950	**8,891**	*193,059*
870	OTHER POWER MAINT EXPENSES		416,231	**18,324**	*397,907*
871	TOTAL OTHER POWER GENERATION EXP		1,167,081	**51,379**	*1,115,702*
872					
873	OTHER POWER SUPPLY EXPENSE				
874	555.1 / PURCHASED POWER	E10	0	**0**	*0*
875	555.2 / COGENERATION & SMALL POWER PROD				
876	CAPACITY RELATED	D10	0	**0**	*0*
877	ENERGY RELATED	E10	0	**0**	*0*
878	TOTAL 555.2/CSPP		0	**0**	*0*
879	555/TOTAL		0	**0**	*0*
880	556 / LOAD CONTROL & DISPATCHING EXPENSES	D10	0	**0**	*0*
881	557 / OTHER EXPENSES	D10	1,913,706	**84,248**	*1,829,458*
882	TOTAL OTHER POWER SUPPLY EXPENSES		1,913,706	**84,248**	*1,829,458*
883					
884	TOTAL PRODUCTION EXPENSES		20,123,230	**887,278**	*19,235,952*

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	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
885	***TABLE 13-DEVELOPMENT OF LABOR RELATED ALLOCATOR***				
886	TRANSMISSION EXPENSES				
887	OPERATION				
888	560 / SUPERVISION & ENGINEERING	L 151	1,558,712	**61,193**	*1,497,519*
889	561 / LOAD DISPATCHING	D11	2,503,896	**98,699**	*2,405,197*
890	562 / STATION EXPENSES	L 129	1,252,413	**49,494**	*1,202,919*
891	563 / OVERHEAD LINE EXPENSES	L 134+139+144	386,995	**15,108**	*371,887*
892	565 / TRANSMISSION OF ELECTRICITY BY OTHERS	E10	0	**0**	*0*
893	566 / MISCELLANEOUS EXPENSES	L 501	160,126	**6,640**	*153,486*
894	567 / RENTS	L 151	37	**1**	*36*
895	TOTAL TRANSMISSION OPERATION		5,862,179	**231,136**	*5,631,043*
896					
897	MAINTENANCE				
898	568 / SUPERVISION & ENGINEERING	L 151	69,852	**2,742**	*67,110*
899	569 / STRUCTURES	L 124	353,404	**13,941**	*339,463*
900	570 / STATION EQUIPMENT	L 129	1,494,700	**59,068**	*1,435,632*
901	571 / OVERHEAD LINES	L 134+139+144	978,483	**38,200**	*940,283*
902	573 / MISCELLANEOUS PLANT	L 151	0	**0**	*0*
903	TOTAL TRANSMISSION MAINTENANCE		2,896,439	**113,951**	*2,782,488*
904					
905	TOTAL TRANSMISSION EXPENSES		8,758,618	**345,087**	*8,413,531*

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	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
906	***TABLE 13-DEVELOPMENT OF LABOR RELATED ALLOCATOR***				
907	DISTRIBUTION EXPENSES				
908	OPERATION				
909	580 / SUPERVISION & ENGINEERING	L 183	2,268,912	**128,133**	*2,140,779*
910	581 / LOAD DISPATCHING	D60	2,631,346	**113,708**	*2,517,638*
911	582 / STATION EXPENSES	L 171	741,803	**20,157**	*721,646*
912	583 / OVERHEAD LINE EXPENSES	L 173+174	2,784,080	**196,758**	*2,587,322*
913	584 / UNDERGROUND LINE EXPENSES	L 175+176	863,274	**14,264**	*849,010*
914	585 / STREET LIGHTING & SIGNAL SYSTEMS	L 181	57,984	**2,924**	*55,060*
915	586 / METER EXPENSES	L 179	3,367,245	**48,430**	*3,318,815*
916	587 / CUSTOMER INSTALLATIONS EXPENSE	L 180	997,875	**91,671**	*906,204*
917	588 / MISCELLANEOUS EXPENSES	L 528	3,339,195	**170,989**	*3,168,206*
918	589 / RENTS	L 183	1,261	**71**	*1,190*
919	TOTAL DISTRIBUTION OPERATION		17,052,975	**787,106**	*16,265,869*
920					
921	MAINTENANCE				
922	590 / SUPERVISION & ENGINEERING	L 183	270,338	**15,267**	*255,071*
923	591 / STRUCTURES	L 165	0	**0**	*0*
924	592 / STATION EQUIPMENT	L 171	1,852,758	**50,344**	*1,802,414*
925	593 / OVERHEAD LINES	L 173+174	3,894,609	**275,242**	*3,619,367*
926	594 / UNDERGROUND LINES	L 175+176	778,269	**12,860**	*765,409*
927	595 / LINE TRANSFORMERS	L 177	26,331	**2,389**	*23,942*
928	596 / STREET LIGHTING & SIGNAL SYSTEMS	L 181	319,161	**16,095**	*303,066*
929	597 / METERS	L 179	574,879	**8,268**	*566,611*
930	598 / MISCELLANEOUS PLANT	L 183	185,522	**10,477**	*175,045*
931	TOTAL DISTRIBUTION MAINTENANCE		7,901,867	**390,942**	*7,510,925*
932	TOTAL DISTRIBUTION EXPENSES		24,954,842	**1,178,047**	*23,776,795*
933					
934	CUSTOMER ACCOUNTING EXPENSES				
935	901 / SUPERVISION	L 936	283,569	**15,930**	*267,639*
936	902 / METER READING	CW902	3,594,065	**201,904**	*3,392,161*
937	903 / CUSTOMER RECORDS & COLLECTIONS	CW903	5,809,150	**219,657**	*5,589,493*
938	904 / UNCOLLECTIBLE ACCOUNTS	CW904	0	**0**	*0*
939	905 / MISC EXPENSES	L 936-938	0	**0**	*0*
940	TOTAL CUSTOMER ACCOUNTING EXPENSES		9,686,784	**437,491**	*9,249,293*
941					
942	CUSTOMER SERVICES & INFORMATION EXPENSES				
943	907 / SUPERVISION	L 947	249,937	**5,952**	*243,985*
944	908 / CUSTOMER ASSISTANCE	L 540	3,108,334	**74,025**	*3,034,309*
945	908 / DSM RIDER	CIDA	0	**0**	*0*
946	909 / INFORMATION & INSTRUCTIONAL	L 542	0	**0**	*0*
947	910 / MISCELLANEOUS EXPENSES	L 944+946	479,927	**11,429**	*468,498*
948	TOTAL CUST SERV & INFORMATN EXPENSES		3,838,198	**91,407**	*3,746,791*

IDAHO POWER COMPANY
JURISDICTIONAL REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2009

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
949	***TABLE 13-DEVELOPMENT OF LABOR RELATED ALLOCATOR***				
950	ADMINISTRATIVE & GENERAL EXPENSES				
951	920 / ADMINISTRATIVE & GENERAL SALARIES	PTDCAS	34,880,572	**1,522,005**	*33,358,567*
952	921 / OFFICE SUPPLIES	PTDCAS	211,272	**9,219**	*202,053*
953	922 / ADMIN & GENERAL EXPENSES TRANSFERRED-CR	SUBEX	0	**0**	*0*
954	923 / OUTSIDE SERVICES	PTDCAS	0	**0**	*0*
955	924 / PROPERTY INSURANCE				
956	PRODUCTION - STEAM	L 109	0	**0**	*0*
957	ALL RISK & MISCELLANEOUS	P110P	159,492	**6,665**	*152,827*
958	TOTAL ACCOUNT 924		159,492	**6,665**	*152,827*
959	925 / INJURIES & DAMAGES	LABOR	109,957	**4,798**	*105,159*
960	926 / EMPLOYEE PENSIONS & BENEFITS	LABOR	0	**0**	*0*
961	927 / FRANCHISE REQUIREMENTS	CIDA	0	**0**	*0*
962	928 / REGULATORY COMMISSION EXPENSES				
963	928.101 / FERC ADMIN ASSESS & SECURITIES				
964	CAPACITY RELATED	D10	0	**0**	*0*
965	ENERGY RELATED	E10	0	**0**	*0*
966	928.101 / FERC ORDER 472	E99	0	**0**	*0*
967	928.101 / FERC MISCELLANIOUS	L RESREV	0	**0**	*0*
968	928.102 FERC RATE CASE	RESREV	0	**0**	*0*
969	928.104 / FERC OREGON HYDRO	RESREV	0	**0**	*0*
970	SEC EXPENSES	L 199	0	**0**	*0*
971	928.202 / IDAHO PUC -RATE CASE	CIDA	0	**0**	*0*
972	928.203 / IDAHO PUC - OTHER	CIDA	0	**0**	*0*
973	928.301 / OREGON PUC - FILING FEES	CODA	0	**0**	*0*
974	928.302 / OREGON PUC - RATE CASE	CODA	0	**0**	*0*
975	928.303 / OREGON PUC - OTHER	CODA	0	**0**	*0*
976	IPC/PUC JSS TRUE-UP ADJ	PTD	0	**0**	*0*
977	TOTAL ACCOUNT 928		0	**0**	***0***
978	929 / DUPLICATE CHARGES	SUBEX	0	**0**	*0*
979	930.1 / GENERAL ADVERTISING	RELAB	0	**0**	*0*
980	930.2 / MISCELLANEOUS EXPENSES	PTDCAS	146,512	**6,393**	*140,119*
981	931 / RENTS	L 197	0	**0**	*0*
982	TOTAL ADM & GEN OPERATION		35,507,805	**1,549,079**	*33,958,726*
983	PLUS:				
984	935 / GENERAL PLANT MAINTENANCE	P3908	973,275	**46,031**	*927,244*
985	416 / MERCHANDISING EXPENSE	E10	0	**0**	*0*
986	TOTAL OPER & MAINT EXPENSES		103,842,752	**4,534,420**	*99,308,332*
987	**TOTAL LABOR - RATIO (%)**		100.00%	**4.37%**	*95.63%*
988					

IDAHO POWER COMPANY
JURISDICTIONAL REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2009

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
989	***TABLE 14-ALLOCATION FACTORS***				
990					
991	CAPACITY RELATED KW				
992	PRODUCTION RELATED COINCIDENT PEAKS @ GEN LEVEL	D10	2,470,397	**108,755**	*2,361,641*
993	SYSTEM TRANSMISSION SERVICE @ GENERATION LEVEL	D11	2,759,021	**108,755**	*2,650,265*
994	RETAIL TRANSMISSION SERVICE @ GENERATION LEVEL	D12	2,461,511	**108,755**	*2,352,755*
995	DISTRIBUTION SERVICE @ GENERATION LEVEL	D60	2,299,499	**99,368**	*2,200,132*
996					
997	ENERGY RELATED MWH				
998	GENERATION LEVEL (PSP)	E10	15,951,230.4	**740,533**	*15,210,697*
999	CUSTOMER LEVEL	E99	16,225,126.7	**679,813**	*15,545,314*
1000					
1001	CUSTOMER RELATED FACTORS				
1002	369-DIRECT ASSIGNMENT	DA369	54,698,080	**2,840,618**	*51,857,462*
1003	370-DIRECT ASSIGNMENT (PLANT)	DA370	65,830,908	**946,820**	*64,884,088*
1004	370-DIRECT ASSIGNMENT (ACCUM DEPR)	DA370AD	13,918,914	**67,630**	*13,851,284*
1005	370-DIRECT ASSIGNMENT (DEPR)	DA370D	5,779,742	**879,192**	*4,900,550*
1006	902-CUSTOMER WEIGHTED	CW902	5,752,965	**323,185**	*5,429,780*
1007	903-CUSTOMER WEIGHTED	CW903	11,773,960	**445,199**	*11,328,761*
1008	904-CUSTOMER WEIGHTED	CW904	3,358,203	**145,784**	*3,212,419*
1009	909-DIRECT ASSIGN-AVG.NO.CUST.	DA909	483,194	**18,251**	*464,944*

IDAHO POWER COMPANY
JURISDICTIONAL REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2009

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
1010	***TABLE 14-ALLOCATION FACTORS***				
1011					
1012	DIRECT ASSIGNMENTS				
1013	252-CUSTOMER ADVANCES	DA252	31,785,562	**43,162**	*31,742,400*
1014	350-LAND & LAND RIGHTS	DA350	187,730	**1,144**	*186,586*
1015	352-STRUCTURES & IMPROVEMENTS	DA352	230,972	**0**	*230,972*
1016	353-STATION EQUIPMENT	DA353	2,390,275	**36,494**	*2,353,781*
1017	354-TOWERS & FIXTURES	DA354	186,616	**0**	*186,616*
1018	355-POLES & FIXTURES	DA355	2,995,391	**33,230**	*2,962,161*
1019	356-OVERHEAD CONDUCTORS & DEVICES	DA356	2,149,803	**28,853**	*2,120,950*
1020	359-ROADS & TRAILS	DA359	14,987	**0**	*14,987*
1021	360LAND & LAND RIGHTS-SITUS	DA360S	4,712,126	**135,502**	*4,576,624*
1022	360LAND & LAND RIGHTS-DA	DA360	2,953	**0**	*2,953*
1023	360LAND & LAND RIGHTS-CIAC	DA360C	89,389	**(278)**	*89,667*
1024	361-STRUCTURES & IMPROVEMENTS-SITUS	DA361S	24,243,495	**662,964**	*23,580,531*
1025	361-STRUCTURES & IMPROVEMENTS-DA	DA361	271,060	**0**	*271,060*
1026	361-STRUCTURES & IMPROVEMENTS-CIAC	DA361C	4,463,306	**30,275**	*4,433,031*
1027	362-STATION EQUIPMENT-SITUS	DA362S	164,446,291	**4,891,863**	*159,554,428*
1028	362-STATION EQUIPMENT-DA	DA362	1,575,233	**0**	*1,575,233*
1029	362-STATION EQUIPMENT-CIAC	DA362C	18,276,720	**92,041**	*18,184,679*
1030	364-POLES, TOWERS & FIXTURES-NET	DA364	206,739,181	**15,545,101**	*191,194,080*
1031	365-OVERHEAD CONDUCTORS & DEVICES-NET	DA365	109,387,114	**6,840,067**	*102,547,047*
1032	366-UNDERGROUND CONDUIT-NET	DA366	46,883,583	**657,860**	*46,225,723*
1033	367-UNDERGROUND CONDUCTORS & DEVICES-NET	DA367	174,801,765	**3,000,639**	*171,801,126*
1034	368-LINE TRANSFORMERS-NET	DA368	366,975,446	**33,292,126**	*333,683,320*
1035	371-INSTALLATIONS ON CUSTOMER PREMISES-NET	DA371	2,574,383	**236,500**	*2,337,883*
1036	373-STREET LIGHTING SYSTEMS-NET	DA373	4,134,967	**208,518**	*3,926,449*
1037	451-REVENUE - MISCELLANEOUS SERVICE	DA451	3,669,976	**58,826**	*3,611,149*
1038	454-REVENUE - FACILITIES CHARGE	DA454	6,558,148	**422,140**	*6,136,008*
1039	454-REVENUE - MISCELLANEOUS	DA454MISC	1	**0**	*1*
1040	908-OTHER CUSTOMER ASSISTANCE	DA908	8,510,205	**202,671**	*8,307,534*
1041	440-RETAIL SALES REVENUE	RETREV	741,988,731	**32,433,692**	*709,555,039*
1042	447-WHOLESALE SALES REVENUE	RESREV	1	**0**	*1*
1043	456-REVENUE - WHEELING	DAFIRM	1	**0**	*1*
1044	456-REVENUE - STANDBY SERVICE	DASTNBY	1	**0**	*1*
1045	440-REVENUE OFFSET FOR PLANT ADDITIONS	DAREV	1	**0**	*1*
1046	IDAHO	CIDA	1	**0**	*1*
1047	OREGON	CODA	1	**1**	*0*
1048	FERC	FERC	1	**0**	*1*
1049	NET TO GROSS TAX MULTIPLIER	DA990	1.642	**1.642**	*1.642*

IDAHO POWER COMPANY
JURISDICTIONAL REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2009

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
1050	***TABLE 14-ALLOCATION FACTORS***				
1051					
1052	INTERNALLY DEVELOPED ALLOCATION FACTORS				
1053	PLANT - PROD,TRANS&DIST	PTD	3,804,011,299	**179,912,353**	*3,624,098,945*
1054	LAB - PROD,TRANS,DIST,CUST ACCT&CSIS	PTDCAS	67,361,672	**2,939,309**	*64,422,363*
1055	PLANT - HYDRO,OTHER,TSUBS,DSUBS&GP	P110P	1,657,736,579	**69,275,697**	*1,588,460,882*
1056	PLANT - GEN PLT (390,391,397&398)	P3908	161,518,712	**7,639,097**	*153,879,615*
1057	PLANT - PROD,TRANS,DIST&GEN	P101P	4,060,716,302	**192,053,327**	*3,868,662,975*
1058	O&M - PROD,TRANS,DIST,CUST ACCT&CSIS	SUBEX	484,676,751	**22,118,099**	*462,558,652*
1059	LAB - PROD,TRANS,DIST,CUST ACCT&CSIS	RELAB	1,657,736,579	**69,275,697**	*1,588,460,882*
1060	LAB - ALL LABOR WITHOUT 925-6 "CIRC"	LABOR	102,613,008	**4,477,198**	*98,135,810*

IDAHO POWER COMPANY
JURISDICTIONAL REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2009

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
1061	***TABLE 15-DEVELOPMENT OF DISTRIBUTION JURISDICTIONAL ALLOCATION***				
1062	DISTRIBUTION-IDAHO @ GENERATION LEVEL	D60-ID	2,182,262	**0.0**	*2,182,261.8*
1063	DISTRIBUTION-OREGON @ GENERATION LEVEL	D60-OR	99,368	**99,367.8**	*0.0*
1064					
1065	DISTRIBUTION PLANT				
1066	360 / LAND & LAND RIGHTS				
1067	NET PLANT:				
1068	DISTRIBUTION - IDAHO	D60-ID	4,576,624	**0**	*4,576,624*
1069	DISTRIBUTION - OREGON	D60-OR	135,502	**135,502**	*0*
1070	DISTRIBUTION - SITUS ALLOCATION	DA360S	4,712,126	**135,502**	*4,576,624*
1071	DIRECT ASSIGNMENT	DA360	2,953	0	*2,953*
1072	CIAC:				
1073	DISTRIBUTION - IDAHO	CIDA	89,667	**0**	*89,667*
1074	DISTRIBUTION - OREGON	CODA	(278)	**(278)**	*0*
1075	DISTRIBUTION - SITUS ALLOCATION		89,389	**(278)**	*89,667*
1076	DIRECT ASSIGNMENT		0	0	*0*
1077	TOTAL 360 CIAC	DA360C	89,389	**(278)**	*89,667*
1078					
1079	361 / STRUCTURES & IMPROVEMENTS				
1080	NET PLANT:				
1081	DISTRIBUTION - IDAHO	D60-ID	23,580,531	**0**	*23,580,531*
1082	DISTRIBUTION - OREGON	D60-OR	662,964	**662,964**	*0*
1083	DISTRIBUTION - SITUS ALLOCATION	DA361S	24,243,495	**662,964**	*23,580,531*
1084	DIRECT ASSIGNMENT	DA361	271,060	0	*271,060*
1085	CIAC:				
1086	DISTRIBUTION - IDAHO	CIDA	1,188,010	**0**	*1,188,010*
1087	DISTRIBUTION - OREGON	CODA	30,275	**30,275**	*0*
1088	DISTRIBUTION - SITUS ALLOCATION		1,218,285	**30,275**	*1,188,010*
1089	DIRECT ASSIGNMENT		3,245,021	0	*3,245,021*
1090	TOTAL 361 CIAC	DA361C	4,463,306	**30,275**	*4,433,031*
1091					
1092	362 / STATION EQUIPMENT				
1093	NET PLANT:				
1094	DISTRIBUTION - IDAHO	D60-ID	159,554,428	**0**	*159,554,428*
1095	DISTRIBUTION - OREGON	D60-OR	4,891,863	**4,891,863**	*0*
1096	DISTRIBUTION - SITUS ALLOCATION	DA362S	164,446,291	**4,891,863**	*159,554,428*
1097	DIRECT ASSIGNMENT	DA362	1,575,233	0	*1,575,233*
1098	CIAC:				
1099	DISTRIBUTION - IDAHO	CIDA	6,679,565	**0**	*6,679,565*
1100	DISTRIBUTION - OREGON	CODA	92,041	**92,041**	*0*
1101	DISTRIBUTION - SITUS ALLOCATION		6,771,606	**92,041**	*6,679,565*
1102	DIRECT ASSIGNMENT		11,505,114	0	*11,505,114*
1103	TOTAL 362 CIAC	DA362C	18,276,720	**92,041**	*18,184,679*

IDAHO POWER COMPANY
JURISDICTIONAL REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2009

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
1104	***TABLE 16-ALLOCATION FACTORS-RATIOS***				
1105					
1106	CAPACITY RELATED KW				
1107	PRODUCTION RELATED COINCIDENT PEAKS @ GEN LEVEL	D10	100.00%	**4.40%**	*95.60%*
1108	SYSTEM TRANSMISSION SERVICE @ GENERATION LEVEL	D11	100.00%	**3.94%**	*96.06%*
1109	DISTRIBUTION SERVICE @ GENERATION LEVEL	D60	100.00%	**4.32%**	*95.68%*
1110					
1111	ENERGY RELATED MWH				
1112	GENERATION LEVEL (PSP)	E10	100.00%	**4.64%**	*95.36%*
1113	CUSTOMER LEVEL	E99	100.00%	**4.19%**	*95.81%*
1114					
1115	CUSTOMER RELATED FACTORS				
1116	369-DIRECT ASSIGNMENT	DA369	100.00%	**5.19%**	*94.81%*
1117	370-DIRECT ASSIGNMENT (PLANT)	DA370	100.00%	**1.44%**	*98.56%*
1118	370-DIRECT ASSIGNMENT (ACCUM DEPR)	DA370AD	100.00%	**0.49%**	*99.51%*
1119	370-DIRECT ASSIGNMENT (DEPR)	DA370D	100.00%	**15.21%**	*84.79%*
1120	902-CUSTOMER WEIGHTED	CW902	100.00%	**5.62%**	*94.38%*
1121	903-CUSTOMER WEIGHTED	CW903	100.00%	**3.78%**	*96.22%*
1122	904-CUSTOMER WEIGHTED	CW904	100.00%	**4.34%**	*95.66%*
1123	909-DIRECT ASSIGN-AVG.NO.CUST.	DA909	100.00%	**3.78%**	*96.22%*

IDAHO POWER COMPANY
JURISDICTIONAL REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2009

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
1124	***TABLE 16-ALLOCATION FACTORS-RATIOS***				
1125					
1126	DIRECT ASSIGNMENTS				
1127	252-CUSTOMER ADVANCES	DA252	100.00%	**0.14%**	*99.86%*
1128	350-LAND & LAND RIGHTS	DA350	100.00%	**0.61%**	*99.39%*
1129	352-STRUCTURES & IMPROVEMENTS	DA352	100.00%	**0.00%**	*100.00%*
1130	353-STATION EQUIPMENT	DA353	100.00%	**1.53%**	*98.47%*
1131	354-TOWERS & FIXTURES	DA354	100.00%	**0.00%**	*100.00%*
1132	355-POLES & FIXTURES	DA355	100.00%	**1.11%**	*98.89%*
1133	356-OVERHEAD CONDUCTORS & DEVICES	DA356	100.00%	**1.34%**	*98.66%*
1134	359-ROADS & TRAILS	DA359	100.00%	**0.00%**	*100.00%*
1135	360LAND & LAND RIGHTS-SITUS	DA360S	100.00%	**2.88%**	*97.12%*
1136	360LAND & LAND RIGHTS-DA	DA360	100.00%	**0.00%**	*100.00%*
1137	360LAND & LAND RIGHTS-CIAC	DA360C	100.00%	**-0.31%**	*100.31%*
1138	361-STRUCTURES & IMPROVEMENTS-SITUS	DA361S	100.00%	**2.73%**	*97.27%*
1139	361-STRUCTURES & IMPROVEMENTS-DA	DA361	100.00%	**0.00%**	*100.00%*
1140	361-STRUCTURES & IMPROVEMENTS-CIAC	DA361C	100.00%	**0.68%**	*99.32%*
1141	362-STATION EQUIPMENT-SITUS	DA362S	100.00%	**2.97%**	*97.03%*
1142	362-STATION EQUIPMENT-DA	DA362	100.00%	**0.00%**	*100.00%*
1143	362-STATION EQUIPMENT-CIAC	DA362C	100.00%	**0.50%**	*99.50%*
1144	364-POLES, TOWERS & FIXTURES-NET	DA364	100.00%	**7.52%**	*92.48%*
1145	365-OVERHEAD CONDUCTORS & DEVICES-NET	DA365	100.00%	**6.25%**	*93.75%*
1146	366-UNDERGROUND CONDUIT-NET	DA366	100.00%	**1.40%**	*98.60%*
1147	367-UNDERGROUND CONDUCTORS & DEVICES-NET	DA367	100.00%	**1.72%**	*98.28%*
1148	368-LINE TRANSFORMERS-NET	DA368	100.00%	**9.07%**	*90.93%*
1149	371-INSTALLATIONS ON CUSTOMER PREMISES-NET	DA371	100.00%	**9.19%**	*90.81%*
1150	373-STREET LIGHTING SYSTEMS-NET	DA373	100.00%	**5.04%**	*94.96%*
1151	451-REVENUE - MISCELLANEOUS SERVICE	DA451	100.00%	**1.60%**	*98.40%*
1152	454-REVENUE - FACILITIES CHARGE	DA454	100.00%	**6.44%**	*93.56%*
1153	454-REVENUE - MISCELLANEOUS	DA454MISC	100.00%	**0.00%**	*100.00%*
1154	908-OTHER CUSTOMER ASSISTANCE	DA908	100.00%	**2.38%**	*97.62%*
1155	440-RETAIL SALES REVENUE	RETREV	100.00%	**4.37%**	*95.63%*
1156	447-WHOLESALE SALES REVENUE	RESREV	100.00%	**0.00%**	*100.00%*
1157	456-REVENUE - WHEELING	DAFIRM	100.00%	**0.00%**	*100.00%*
1158	456-REVENUE - STANDBY SERVICE	DASTNBY	100.00%	**0.00%**	*100.00%*
1159	440-REVENUE OFFSET FOR PLANT ADDITIONS	DAREV	100.00%	**0.00%**	*100.00%*
1160	IDAHO	CIDA	100.00%	**0.00%**	*100.00%*
1161	OREGON	CODA	100.00%	**100.00%**	*0.00%*
1162	FERC	FERC	100.00%	**0.00%**	*100.00%*
1163	NET TO GROSS TAX MULTIPLIER	DA990	1.642	**1.642**	*1.642*

IDAHO POWER COMPANY
JURISDICTIONAL REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2009

	DESCRIPTION	ALLOC/ SOURCE	TOTAL SYSTEM	OREGON RETAIL	OTHER
1164	***TABLE 16-ALLOCATION FACTORS-RATIOS***				
1165					
1166	INTERNALLY DEVELOPED ALLOCATION FACTORS				
1167	PLANT - PROD,TRANS&DIST	PTD	100.00%	**4.73%**	*95.27%*
1168	LAB - PROD,TRANS,DIST,CUST ACCT&CSIS	PTDCAS	100.00%	**4.36%**	*95.64%*
1169	PLANT - HYDRO,OTHER,TSUBS,DSUBS&GP	P110P	100.00%	**4.18%**	*95.82%*
1170	PLANT - GEN PLT (390,391,397&398)	P3908	100.00%	**4.73%**	*95.27%*
1171	PLANT - PROD,TRANS,DIST&GEN	P101P	100.00%	**4.73%**	*95.27%*
1172	O&M - PROD,TRANS,DIST,CUST ACCT&CSIS	SUBEX	100.00%	**4.56%**	*95.44%*
1173	LAB - PROD,TRANS,DIST,CUST ACCT&CSIS	RELAB	100.00%	**4.18%**	*95.82%*
1174	LAB - ALL LABOR WITHOUT 925-6 "CIRC"	LABOR	100.00%	**4.36%**	*95.64%*

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE _______

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE IN THE STATE OF OREGON.	))))))

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

TIMOTHY E. TATUM

July 31, 2009

Q. Please state your name and business address.

A. My name is Timothy E. Tatum 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 "Company") as a Manager of Cost of Service in the Pricing and Regulatory Services Department.

Q. Please describe your educational background.

A. I received a Bachelor of Business Administration degree in Economics from Boise State University in 2001. In 2005, I earned a Master of Business Administration degree from Boise State University. I have also attended electric utility ratemaking courses, including "Practical Skills for The Changing Electrical Industry," a course offered through New Mexico State University's Center For Public Utilities, "Introduction to Rate Design and Cost of Service Concepts and Techniques" presented by Electric Utilities Consultants, Inc., and Edison Electric Institute's "Electric Rates Advanced Course."

Q. Please describe your work experience with Idaho Power.

A. I began my employment with Idaho Power in 1996 as a Customer Service Representative in the Company's Customer Service Center. Over the first two years, I handled customer phone calls and other customer-related transactions. In 1999, I began working in the Customer Account Management Center where I was responsible for customer account maintenance in the area of billing and metering.

In June of 2003, after seven years in customer service, I began working as an Economic Analyst on the Energy Efficiency Team. As an Economic Analyst, I maintained proper accounting for Demand-Side Management ("DSM") expenditures, prepared and reported DSM program accounting and activity to management and various external stakeholders, conducted cost-benefit analyses of DSM programs, and provided DSM analysis support for the Company's 2004 Integrated Resource Plan ("IRP").

In August of 2004, I accepted a position as a Pricing Analyst in Pricing and Regulatory Services. As a Pricing Analyst, I provided 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.

In August of 2006, I was promoted to Senior Pricing Analyst. As a Senior Pricing Analyst, my responsibilities expanded to include the development of complex financial studies to determine revenue recovery and pricing strategies, including the preparation of the Company's cost-of-service studies.

In September of 2008, I was promoted to my current position, Manager of Cost of Service. As Manager of Cost of Service I oversee the Company's cost-of-service activities such as power supply modeling, jurisdictional separation studies, class cost-of-service studies, and marginal cost studies.

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

A. My testimony will address the Company's "functionalization" of its proposed Oregon jurisdictional revenue requirement provided to me by Company witness Jeannette Bowman, the Company's 2009 Marginal Cost Analysis, and the proposed allocation of Oregon jurisdictional revenue requirement.

Q. Have you prepared any exhibits as part of your testimony?

A. Yes. I have prepared the following four exhibits as part of my testimony:

1. Exhibit No. 801 presents the Company's functionalized revenue requirement;
2. Exhibit No. 802 is the 2009 Marginal Cost Analysis;
3. Exhibit No. 803 is a summary of marginal costs by customer class, the resulting revenue requirement allocation, and the class-specific unit costs; and
4. Exhibit No. 804 details the Company's proposed revenue requirement allocation.

FUNCTIONALIZATION OF REVENUE REQUIREMENT

Q. Please explain the meaning of functionalization.

A. Before the Company's proposed revenue requirement can be divided among customer classes, costs must be functionalized — that is, identified with utility operating functions. Operating functions recognize the different roles played by the various facilities in the electric utility system. In the Company's accounts, these various roles are recognized to some degree, particularly in the recording of plant costs as generation-, transmission-, or distribution-related. However, this functional breakdown is not sufficiently detailed for cost-of-service purposes.

Q. How are costs further segmented for cost-of-service purposes?

A. For cost-of-service purposes, functionalized costs are further segmented or "classified" as energy-, demand- or customer-related. *Energy-related* costs are generally the variable costs associated with the operation of the generating plants, such as fuel. However, because the Company is heavily reliant on hydro generation, a portion of the hydro and thermal generating plant investment has been classified as energy-related according to the Company's system load factor. *Demand-related costs* are investments in generation, transmission, and distribution plant capacity and the associated operation and maintenance expenses necessary to accommodate the maximum demand imposed on the Company's system. Examples of *customer-related costs* are the plant investments and expenses that are associated with meters and service drops, meter reading, billing and collection, and customer information and services as well as a portion of the investment in the distribution system. These investments and expenses are made and incurred based on the number of customers, regardless of the amount of energy used, and are therefore generally considered to be fixed costs.

Q. Please describe in general terms the process used to functionalize and classify the Company's revenue requirement.

A. In the functionalization process, individual plant items, operations and maintenance expenses, and other operating revenues are examined and, where possible, the associated costs and revenues are assigned to one or more operating functions. The remaining costs and revenues are allocated to the each functional category according to the appropriate allocation basis. Generation costs are further classified as either demand- or energy-related, transmission costs are classified as demand-related, and distribution costs are classified as either demand- or customer-related. The following example illustrates this process: for Accounts 310 through 316, Steam Production, the Company's investment in steam production plant is assigned to the production or generation function and to the demand and energy cost classifications. The resulting functionalization and classification of costs may itself serve as a basis for subsequent allocations. This use is illustrated where the accumulated depreciation for steam production plant is functionalized and classified on the same basis as steam plant investment.

Q. Please describe Exhibit No. 801.

A. Exhibit No. 801 details the development of the Company's functionalized revenue requirement for each of the following categories: (1) generation, (2) transmission, and (3) distribution. As can be seen on Exhibit No. 801, the total Oregon jurisdictional revenue requirement of $39,762,693 has been segmented into the Company's three main operating functions. Generation-related revenue requirement represents approximately $21.2 million or 53.3 percent of the total; transmission represents approximately $4.0 million or 10 percent; and distribution represents $14.6 million or 36.7 percent.

2009 MARGINAL COST ANALYSIS

Q. What methodology was used to allocate the proposed revenue requirement to customer classes in this general rate case proceeding?

A. The proposed revenue requirement has been apportioned to customer classes according to the Company's 2009 Marginal Cost Analysis. In general terms, this study calculates the marginal cost associated with supplying an added unit of electricity or serving an additional customer. A detailed description of the 2009 Marginal Cost Analysis and supporting schedules showing the development of the marginal costs is provided on Exhibit No. 802.

Q. Please summarize the 2009 Marginal Cost Analysis, which is described in greater detail in Exhibit No. 802.

A. The 2009 Marginal Cost Analysis was prepared at my direction according to concept and design specifications of the National Economic Research Associates, Inc. ("NERA") marginal cost model. The NERA model is constantly being refined but the basic concepts and methods have remained the same since Idaho Power began using this method. The study identifies the long-run marginal cost of providing electric service to new load on the Idaho Power Company system. The Company's forecasted growth-related generation, transmission, and distribution costs are identified and classified into the appropriate energy-, demand-, and customer-related components in a manner similar to the classification of the Oregon jurisdictional revenue requirement.

The energy-related marginal costs include net power supply costs, variable operation and maintenance ("O&M") expenses, fuel inventory, and losses. Demand-related costs are comprised of generation, transmission, and distribution investment and associated fixed O&M expenses. Customer-related costs include investment costs that are attributable to anticipated growth in the number of customers served. In this analysis, marginal unit costs are prepared for each functional category for use in apportioning the revenue requirement to customer classes.

Q. How does the 2009 Marginal Cost Analysis compare to the study filed in the Company's last general rate case proceeding, Docket No. UE 167?

A. The 2009 Marginal Cost Analysis was prepared according to a methodology similar to that used to prepare the 2004 Marginal Cost Study ("2004 Study") filed in UE 167.

However, there have been a number of methodological improvements made to the analysis since the 2004 Study, which I will discuss in greater detail later in my testimony.

Q. Please explain how the generation marginal costs for the energy- and demand-related categories were determined.

A. Generation energy-related marginal costs were determined by a simulated operation of the Company's power supply system over 81 streamflow conditions for the five year period 2009 through 2013 using the Company's AURORA Power Supply Model. Base case net power supply expenses were quantified and the model was run a second time with 50 megawatts ("mW") of load added across all hours. The difference in monthly power supply expenses between the base run and the "base-plus-50-MW run" was averaged over the five year period and was divided by the difference in monthly megawatt hours ("mWh") to produce an average monthly marginal cost per megawatt hour.

Generation demand-related marginal costs are based upon the levelized cost of a simple-cycle combustion turbine from Idaho Power's 2006 IRP. The peaking resource selected from the resource portfolio to quantify the marginal generation capacity cost is the Danskin CT1 Combustion Turbine. This resource is the latest peaking resource addition to the Company's rate base. The generation capacity marginal costs are then seasonalized based on the monthly peak hour load surplus/deficiency data, assuming 90th percentile streamflow conditions, 70th percentile average load, and 95th percentile peak-hour load contained in the 2006 IRP.

Q. Please explain how the transmission marginal costs were determined.

A. The marginal cost of transmission reflects planned investment in transmission plant for a ten-year period, 2009 through 2018. Demand-related transmission O&M costs were estimated using historic data for the period 2004 through 2008. Transmission marginal costs were seasonalized in a manner similar to that used to seasonalize the generation capacity marginal costs.

Q. Please provide an overview of how the distribution marginal costs were determined.

A. The distribution marginal costs were developed according to NERA's facilities cost approach. Under this method, distribution costs are divided into three categories: (1) costs that increase due to growth in actual peak demand, (2) design demand-related costs, and (3) customer-related costs. According to the NERA model, design demand-related costs are those costs that are considered fixed over time because they do not change in response to customers' actual loads. Design demand costs are incurred on the basis of the planner's engineering design standards, which reflect the number of customers to be served, and expected maximum demand of those customers, rather than on changes in actual peak demand.

The first category of costs, those that increase due to growth in actual peak demand, is comprised of distribution substation carrying costs and related O&M expense. The second category of costs is comprised of the carrying costs of the plant located between the substation and the service drop, and the associated O&M expense. This plant includes primary lines, secondary lines, poles, transformers, and associated equipment. Customer-related costs include the carrying cost of the service drop, customer service and informational expense, and customer accounting expense. Customer service and informational expense refers to those expenses included in FERC Accounts 907 through 910 and customer accounting expense refers to those expenses included in FERC Accounts 901 through 905. The service drop is considered by NERA to be part of the design demand-based category, but Idaho Power's practice has been to include the service drop as part of the customer-related category, as it has been done in this study.

Q. Please describe page 30 of Exhibit No. 802, Schedule 16.

A. Page 30 of Exhibit No. 802, Schedule 16, presents the results of the 2009 Marginal Cost Analysis. The study results are presented in terms of marginal unit costs for each customer class. The marginal unit cost values for the generation and transmission functional categories are provided as monthly values and the distribution-related marginal unit costs are provided as annual values. The distribution-related marginal costs reflect the attribution of primary and secondary distribution costs to the appropriate classes depending on the voltage level of service (primary, secondary, or transmission).

Q. Why are monthly marginal unit cost values provided for the generation and transmission functional categories, while only annual values are provided for the distribution category?

A. Marginal unit costs are prepared as either monthly or annual values in order to align with the associated allocation basis. Marginal unit costs are developed for the purpose of determining the total marginal costs by functional category by customer class. In this study, the total marginal costs by customer class were determined by multiplying the marginal unit costs for each functional category by the appropriate allocation basis for each customer class; i.e., energy, demand, or number of customers. For example, the total generation and transmission capacity marginal costs for each class were determined by multiplying each class' 12 monthly coincident peak demand values by the corresponding monthly marginal unit cost. Similarly, the total energy-related generation marginal costs for each class were determined by multiplying each class' monthly energy values by the corresponding monthly marginal unit cost. The marginal unit costs for the generation and transmission functional categories are prepared as monthly values to recognize that those cost categories vary by month and, to a greater extent, seasonally.

Consistent with that rationale, the distribution marginal unit costs have been prepared as annual values in order to recognize that distribution costs do not vary by month or seasonally to the extent of the other functional categories. The total distribution demand-related marginal costs by customer class were determined by applying the class-specific distribution demand-related marginal unit cost to the single highest monthly non-coincidental peak demand value for each customer class. Similarly, the total distribution customer-related marginal costs by customer class were determined by applying the class-specific distribution customer-related marginal unit cost to the corresponding annual customer counts for each class. The use of annual values in the case of distribution costs achieves the goal of aligning the marginal unit costs with the associated allocation basis.

Q. Idaho Power submitted a marginal cost analysis as part of the UE 167 case. How do the results of the current study compare to the results of the study submitted in UE 167?

A. The 2009 Marginal Cost Analysis results are comparable to the results of the 2004 Study with the exception of a few specific areas where methodological improvements have been made to the study.

Annual generation capacity costs as computed in the 2004 Study were $81 per kilowatt ("kW") in 2003 dollars and in the current study the costs have declined to $45 per kW in 2009 dollars. This decline in marginal capacity cost is likely the result of a reduction in demand for gas turbines that has occurred since 2003, a time when combustion turbines were in high demand due to the Western Energy Crisis. On the other hand, average annual energy costs have increased from $35.40 per MWh to $60.31 per MWh. This change can be attributed to a number of cost drivers, including increases in fuel costs, such as coal and natural gas as well as increases in market energy prices.

The cost of annual transmission capacity was $13 per kW in the 2004 Study and is now $173 per kW in the current study. This change is due to the inclusion of system expansion costs in the derivation of the cost of annual transmission capacity. In the 2004 Study, the marginal cost of transmission capacity included only the costs associated with integrating a new network resource to meet native load service requirements. In the current study, the cost of annual transmission capacity is the sum two components: (1) network integration costs of $18 per kW (comparable to the 2004 Study value of $13) and (2) the costs associated with planned transmission system expansion over a ten-year period totaling $155 per kW. At the time the 2004 Study was prepared, the Company was not planning any transmission expansion projects. The current study reflects the Company's plans for a number of large transmission system expansion projects over the next 10 years.

The marginal cost of distribution substation capacity was $4.64 in the 2004 Study and is $18.80 per kW in the current study. This significant change in the marginal cost can be attributed largely to a change in the method used to prepare the value. In the 2004 Study, the marginal cost of distribution substation capacity was calculated by dividing the annual average of planned new investment in distribution substation capacity by total distribution peak load over the five-year planning period. In the current study, the marginal cost of distribution substation capacity was calculated by dividing total planned new investment in distribution substation capacity over the next 5 years by total distribution peak load growth for the same period. Because total investment, a larger number, is used in the numerator of the equation, the resulting marginal cost value is larger than would have been the case under the prior method.

Distribution facilities investment costs ranged from $17.88 per kW to $50.04 per kW in the 2004 Study. In the current study, these costs ranged from $17.95 per kW to $54.88 per kW. Distribution customer-related costs ranged from $125.28 per customer to $4,372.44 per customer in the 2004 Study. In the current study, these costs ranged from $87.15 per customer to $3,165.74 per customer.

Overall, the results of the 2009 Marginal Cost Analysis appear reasonable when compared to the 2004 Study, especially when considering the changes in costs and methodology that have occurred in the intervening years.

MARGINAL COST-BASED REVENUE REQUIREMENT ALLOCATION

Q. Once the marginal costs for each functional category were determined, how were those marginal costs utilized to allocate the Oregon jurisdictional revenue requirement to each customer class?

A. Exhibit No. 803 presents the total marginal cost by customer class and by functional category resulting from the 2009 Marginal Cost Analysis. As can be seen on page 1 of Exhibit No. 803, the total functionalized revenue requirement from Exhibit No. 801 has been allocated to each customer class in proportion to the marginal cost by class for each functional category. This allocation represents the Company's quantification of the cost of providing service to each customer class or "cost-of-service." The total marginal costs exceed the Oregon jurisdictional revenue requirement and are not the basis of recovery from classes, but rather are utilized to determine each class's responsibility or share of the total Oregon jurisdictional revenue requirement.

Pages 2 through 5 of Exhibit No. 803 present the class-specific units costs. The class-specific unit costs represent the revenue requirement by billing unit for each customer class. The unit costs ultimately help guide the rate design process by providing a cost-of-service basis for each rate component.

Q. Line 26, page 1 of Exhibit No. 803 presents the "Direct Assignment" of a portion of the customer-related distribution costs. What portion of the Company's revenue requirement has been directly assigned to customer classes on line 26?

A. The revenue requirement amount on line 26, page 1 of Exhibit No. 803 is comprised of rate base associated with FERC Accounts 371 and 373 and expenses associated with FERC Accounts 585, 587, and 598. The revenue requirement amount on line 26 is largely associated with expenses related to rendering services at customers' premises. Examples of such services include inspecting customers' premises; installing, testing, and removing leased equipment; and testing customer-owned equipment. The remainder of the revenue requirement on line 26 is associated with the Company's lighting service customer classes.

Q. Please describe the results of marginal cost-based revenue requirement allocation presented on Exhibit No. 803.

A. As can be seen on Exhibit No. 803, a pure marginal cost-based allocation of the Oregon jurisdictional revenue requirement results in increases of 33.17 percent for Residential Service, 36.87 percent for Small General Service, 6.46 percent for Large General Service-Secondary Voltage Level, 18.48 percent for Large General Service-Primary Voltage Level, -22.72 percent for Area Lighting Service, 5.45 percent for Large Power Service – Primary Voltage Level, -11.35 percent for Large Power Service –Transmission Voltage Level, 92.90 percent for Irrigation Service, 20.34 percent for Unmetered General Service, 9.04 percent for Municipal Street Lighting Service, and 115.40 percent for Traffic Control Lighting Service.

PROPOSED REVENUE REQUIREMENT ALLOCATION

Q. What is the Company's general philosophy on revenue requirement recovery from customer classes?

A. The Company's primary approach to revenue requirement allocation in the last several general rate cases has been to establish class revenue requirements that as accurately as possible reflect the costs of serving those customer classes. Accordingly, the Company's ratemaking proposals generally advocate movement towards the cost-of-service results, which assign costs to those customer classes that cause the Company to incur the costs.

Q. Are there other objectives that may be considered in the ratemaking process?

A. Yes. The Commission may consider a number of other objectives, such as rate stability, rate shock, and ability to pay in the determination of rates.

Q. How did you approach the determination of the Company's proposed revenue requirement for each customer class?

A. A pure marginal cost-based revenue requirement spread would result in substantial increases to Irrigation Service and Traffic Control Lighting Service. In order to mitigate the magnitude of the rate increase to each of these customer classes that would be necessary to bring them to current cost-of-service levels, the Company is proposing to cap the percentage increase for Irrigation Service and Traffic Control Lighting Service at 75 percent of the increase resulting from a pure cost-of-service perspective or 44.69 percent and 61.55 percent, respectively. Furthermore, a pure marginal cost-based revenue requirement spread would result in decreases for Area Lighting Service and Large Power Service –Transmission Voltage Level. For these classes, the Company proposes to apply a 0.00 percentage change "floor" resulting in neither an increase nor a decrease.

Q. Did you discuss the results of the cost-of-service study with Mr. Said before deciding to apply the caps and floors to the specified customer classes?

A. Yes. I discussed the results of the cost-of-service study and potential rate spread scenarios with Company witness Gregory Said, who is responsible for the overall preparation of this case. My revenue allocation recommendation is a result of those discussions.

Q. Do you have an exhibit that details the class revenue requirement determination?

A. Yes. Exhibit No. 804 is a four-page exhibit that steps through the revenue requirement allocation process from the cost-of-service results to the ultimate proposal for each customer class. Page 1 of Exhibit No. 804 is the pro forma normalized test year sales and revenues. Page 2 details the results from the cost-of-service study and illustrates the revenue changes that would be made to each customer class to obtain the cost-of-service results. Page 3 shows the revenue shortfall that resulted by applying the caps and floors to the specified customer classes. Finally, page 4 shows the proposed increase to the other customer classes which resulted from spreading the shortfall created by the mitigation to the remaining classes in order to obtain the total Oregon jurisdictional target revenue requirement. I have provided the results from page 4 to Company witness Michael Youngblood and his Rate Design Team for use in determining the individual rates for the Company's general tariff customers.

Q. Does this conclude your testimony?

A. Yes.

Idaho Power/801
Witness: Timothy E. Tatum

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Timothy E. Tatum
Revenue Requirement by Functional Category

July 31, 2009

IDAHO POWER COMPANY
Revenue Requirement By Functional Category
State of Oregon
Test Year - 2009

	Total Revenue Requirement	% of Total
Generation		
Demand-Related	$ 8,339,392	21.0%
Energy-Related	12,854,145	32.3%
Transmission	3,983,187	10.0%
Distribution		
Demand-Related	10,919,664	27.5%
Customer-Related	3,666,305	9.2%
Total	$ 39,762,693	100.0%

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Timothy E. Tatum
Marginal Cost Analysis

July 31, 2009

2009 Marginal Cost Analysis – Technical Description

The following is a technical description of the 2009 Marginal Cost Analysis. The concept and design of the 2009 Marginal Cost Analysis is from the National Economic Research Associates Inc (NERA) marginal cost model. The NERA model is constantly being refined but the basic concepts and methods have remained the same since Idaho Power began using this method. In this analysis, forecasted growth-related generation, transmission and distribution costs are identified and classified into the appropriate energy-, demand- and customer-related components for use in the Company's class cost-of-service model. The energy-related marginal costs include net power supply costs, variable operation and maintenance (O&M) expenses, fuel inventory and losses. Demand-related costs are comprised of generation, transmission and distribution capacity investment and associated fixed O&M expenses. Customer-related costs include investment costs that are attributable to anticipated growth in the number of customers served.

Generation Marginal Costs

Marginal Cost of Energy. The marginal costs of energy were determined from the simulated operation of the Company's power supply system over 81 streamflow conditions for the five-year period 2009 through 2013. Base case net power supply expenses were quantified and the model was run a second time with fifty megawatts of load added across all hours. The monthly differences in power supply expenses between the base run and the "base-plus-50-MW run" was averaged over the five-year period and was divided by the difference in monthly megawatt hours to produce an average monthly marginal cost per megawatt hour. The 2009 test year net power supply run was used for the 2009 base marginal cost run. For the years 2010 through 2013, projected loads along with currently planned resource additions at the time of the study were used. The 2009 test year gas prices were used, adjusted for each of the successive years using the Utility Natural Gas Index from the Global Insight 30-year US Economic Outlook, March 2009. Coal plant operating characteristics, with the exception of coal costs, and CSPP purchased power volumes from the 2009 analysis were used for the entire period, 2010 through 2013. Added to the average monthly marginal cost per megawatt hour was the revenue requirement associated with marginal fuel inventory, and the marginal variable O&M expense. This loaded energy cost was then increased for losses at the transmission and distribution levels of service. Complete monthly marginal energy costs can be found on Schedule 1.

Marginal Costs of Generation Capacity. The annual marginal cost of generation capacity was derived from the inclusion of Danskin CT1 Power Plant into rate base (Case No. IPC-E-08-1) and from Idaho Power's 2006 Integrated Resource Plan (IRP). The peaking resource selected from the resource portfolio to quantify the marginal cost of capacity was the Danskin CT1 Combustion Turbine. Plant investment included in the Company's application was used and fixed O&M expenses were obtained from the 2006 IRP Technical Appendix, p.55. The reserve margin is 11% (2006 IRP, p. 37). The marginal cost of generation capacity can be found on Schedule 2, page 1 of 2.

Seasonalization of Marginal Cost of Generation Capacity. The seasonalization of the marginal cost of generation capacity is based on information from the 2006 IRP. The Company plans new peaking generation capacity based on monthly peak hour load surplus/deficiency data, assuming 90th percentile streamflow conditions, 70th percentile average load and 95th percentile peak-hour load (2006 IRP Technical Appendix, p. 78). On this basis, during the five years 2009 through 2013, the IRP identified the months of May, June, July, August, September, November and December as months of anticipated deficiency. These are the months that were assigned generation capacity costs in the 2009 Marginal Cost Analysis. The relative sizes of the five-year average monthly deficiencies were used to define the share of annual capacity cost assigned to each month as shown on Schedule 2, page 2 of 2.

Marginal Cost of Transmission Capacity

The marginal cost of transmission reflects planned investment included in the capital budget for the next ten years. The investment costs are for the years 2009 through 2018. Demand related transmission O&M was estimated using historic data for the period 2004 through 2008. Marginal transmission costs are displayed on Schedule 3, page 1 of 2.

Seasonalization of the Marginal Cost of Transmission. The marginal cost of transmission capacity represents the sum two distinct components; 1) network integration cost associated with integrating a new network resource to meet native load service requirements and 2) the costs associated with planned transmission system expansion. Since the resource integration portion of marginal transmission investment is driven by the need for new generation resources, as identified in the 2006 IRP, these costs were assigned to months in the same manner as marginal cost of generation capacity. The investment in the second component of costs, new system expansion, is driven by peak load growth on the system, irrespective of the introduction of new resources onto the grid. Therefore, that portion of marginal costs is assigned to the months based on relative monthly peak load growth from 2009 through 2018. The two components are summed, by month. This method results in the assignment of marginal costs of transmission capacity to each of the twelve months of the year. The seasonal assignment of marginal transmission capacity costs can be found on Schedule 3, page 2 of 2.

Distribution Marginal Costs

To quantify marginal distribution costs, the Company used the “facilities cost method,” as described by NERA. Under this method costs are divided into three categories: costs that increase with growth in actual peak demand, design demand-related costs, and customer-related costs. The first category is comprised of distribution substation carrying costs and related O&M expenses. The second category is comprised of the carrying costs of plant located between the distribution substation and the service drop, as well as associated O&M expense. This plant includes primary lines, secondary lines, poles, transformers and associated equipment. The service drop is considered by NERA to be part of the design demand-based category, but Idaho Power’s practice is to include the service drop in customer-related costs. The Company deviates from NERA methodology in this manner because the costs of the service drop are the direct result of providing service to a specific new customer, and do not vary with changes in the customer's load. By categorizing service drops as customer-related, the Company believes that a more precise attribution of customer cost responsibility to the classes results than would otherwise be the case. Customer-related costs also include the carrying cost of the meter and associated O&M expense, the carrying cost of the service drop, customer service & informational expense, and customer accounts expense.

Distribution Substation Costs. In order to quantify growth-related distribution substation costs, projected investment in new upgrades and substation was identified for the period 2009 through 2013. The forecast growth in distribution peak load was derived by multiplying the forecast system peak load (2006 IRP Technical Appendix, p. 27-31) by a percentage that reflects the 2008 ratio of distribution peak load to total system peak load. Projected investment was then divided by forecast growth in distribution peak load to arrive at marginal distribution substation cost per kW as shown on Schedule 4, page 1 of 2. Marginal distribution substation O&M expense was developed using the Company's total forecast annual distribution O&M expense for the planning period, to which a ratio was applied reflecting the historical relationship between distribution substation O&M expense and total distribution O&M expense. The forecast annual distribution substation O&M expenses were then divided by the forecast distribution peak load and averaged, resulting in marginal distribution substation O&M cost per kW as shown on Schedule 4, page 2 of 2.

Marginal Distribution Facilities Cost. The second cost category is distribution facilities cost, which covers distribution components between the substation and the service drop, as well as associated O&M expense. The first step in quantifying these costs was to price each feeder on the system at current prices. These costs were then allocated to rate classes based on the relative demand of each class by feeder. Finally, each rate class's total cost was divided by its share of total feeder capacity to arrive at a marginal distribution facilities cost per kW, which can be found on Schedule 5, page 1 of 2. Marginal distribution facilities O&M expense was developed using the Company's total forecast annual distribution O&M expense for the planning period, to which a ratio was applied reflecting the historical relationship between distribution facilities O&M expense and total distribution O&M expense. The forecast annual distribution facilities O&M expense was then divided by the forecast peak load and averaged, resulting in marginal distribution facilities O&M cost per kW as shown on Schedule 5, page 2 of 2. Per NERA methodology, it was assumed that marginal distribution facilities O&M expense for a secondary customer is twice the expense of a primary customer.

Marginal Meter Cost. Marginal meter investment per customer for each rate class was developed by determining the types of meters the Company is currently installing for each rate class, then pricing these meters at current cost. A summary of these costs by rate class can be found on Schedule 6, page 1 of 4. Associated O&M was developed using the Company's total forecast annual distribution O&M expense for the planning period, to which a ratio was applied reflecting the historical relationship between meter O&M expense and total distribution O&M expense. A weighted number of customers by class was then derived by multiplying the number of customers in each class by a factor reflecting the relative cost of meters per customer. This calculation is illustrated on Schedule 6, page 4 of 4. The forecast annual meter O&M expenses were then divided by the forecast number of weighted customers to arrive at a system average expense in dollars per weighted customer for each year of the planning period. The results for the five years were then averaged, producing a system average meter O&M expense per weighted customer, displayed on Schedule 6, page 3 of 4. This system average was multiplied by class factors based on relative meter cost to estimate the expense for each actual customer by rate class as shown on Schedule 6, page 2 of 4.

Marginal Service Drop Costs. The cost of the service drop was developed for both single-phase and three-phase service. A weighted cost was applied to each rate class based on the proportion of single-phase to three-phase meters of new meter installs during the period January 2009 through May 2009. Only overhead service was calculated because the Company has a rule in place that provides for a charge to the customer when underground service attachments are desired. The costs of both a single-phase and three-phase drop are shown on Schedule 7, along with the relative percentages of single-phase and three-phase customers by rate class.

Marginal Customer Accounts Expense. To estimate marginal customer accounts expense, total customer accounts expense was forecasted for each of the years 2009 through 2013. These annual expense amounts were then divided by the forecasted number of weighted customers for the same time period. The result was a system average expense in dollars per weighted customer for each year of the planning period. The weighted number of customers was derived by multiplying the number of customers in each class by a factor reflecting the relative size of this expense, per customer, for each class. This calculation is illustrated on Schedule 8, page 3 of 3. The average expense values for the five years were then averaged, producing a system average customer accounts expense per weighted customer as displayed on Schedule 8, page 2 of 3. This system average was then multiplied by the class factors to arrive at customer accounts expense per actual customer by class as shown on Schedule 8, page 1 of 3.

Marginal Customer Service & Informational Expense. Customer service & informational expense was forecasted for the planning period 2009 through 2013, then divided by the forecast number of customers for the same period and averaged, producing marginal customer service & informational expense per customer as shown on Schedule 9. It is assumed that customer service & informational expense per customer does not vary greatly across classes, so these costs were not weighted in the same manner as other customer-related costs.

Development of Marginal Annual Distribution Costs. To arrive at marginal annual distribution costs, both substation and facilities costs were adjusted in the same manner. First, these costs were adjusted for general plant loading, then the annual economic carrying charge was applied and A&G loading was added. Related expenses were adjusted for A&G loading, and the revenue requirement for working capital was added, resulting in total annual marginal distribution costs per kW. A summary of annual marginal distribution substation costs and annual marginal distribution facilities costs can be found on Schedules 10 and 11, respectively. Customer-related costs were adjusted for carrying charges and loading in a similar manner. Meter investment and the service drop were adjusted for general plant loading, the annual economic carrying charge was applied and A&G loading was added. Related expenses were adjusted for A&G loading, and the revenue requirement for working capital was added, resulting in total annual customer-related marginal distribution costs per customer as shown on Schedule 12.

<u>Development of Loaders and Factors.</u> Annual economic carrying charge rates were prepared for a combustion turbine, transmission plant, and distribution plant. The carrying charges reflect the 2009 test year weighted cost of capital and resource lives of each asset as derived in the Company's 2003 depreciation study. A summary of these charges can be found on Schedule 13. General plant, administrative & general, and materials & supplies loading factors were derived from an average of historic data from the period 2004 through 2008. The factor representing the revenue requirement percentage for working capital was derived using the Company's 2009 test year weighted cost of capital and expected tax rates. A summary of loaders is displayed on Schedule 14.

IDAHO POWER COMPANY
Marginal Cost Analysis 2009
Marginal Cost of Energy - Dollars/MWh

Line		January	February	March	April	May	June	July	August	September	October	November	December	Annual Avg.
(1)	Marginal Generation Cost at Generation 1/	$58.26	$39.08	$35.23	$31.18	$31.69	$32.12	$118.36	$82.01	$55.47	$45.09	$54.80	$59.18	$56.27
(2)	Marginal Fuel Inventory	$17.34	$17.34	$17.34	$17.34	$17.34	$17.34	$17.34	$17.34	$17.34	$17.34	$17.34	$17.34	
(3)	Cost of Capital & Taxes for Fuel Inventory (2) x 12.28% 2/	$2.13	$2.13	$2.13	$2.13	$2.13	$2.13	$2.13	$2.13	$2.13	$2.13	$2.13	$2.13	
(4)	Marginal Variable O & M 3/	$4.64	$4.64	$4.64	$4.64	$4.64	$4.64	$4.64	$4.64	$4.64	$4.64	$4.64	$4.64	
(5)	Marginal energy cost at Generation	$65.03	$45.85	$42.00	$37.95	$38.46	$38.89	$125.13	$88.78	$62.24	$51.86	$61.57	$65.95	$60.31
	Average System Loss Factor Coefficients at: 4/													
(6)	Transmission	1.035	1.035	1.035	1.035	1.035	1.035	1.035	1.035	1.035	1.035	1.035	1.035	
(7)	Distribution Station	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050	
(8)	Distribution Primary	1.074	1.074	1.074	1.074	1.074	1.074	1.074	1.074	1.074	1.074	1.074	1.074	
(9)	Distribution Secondary	1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109	1.109	
	Marginal Energy Cost at Service Level													
(10)	Power Supply (5)	$65.03	$45.85	$42.00	$37.95	$38.46	$38.89	$125.13	$88.78	$62.24	$51.86	$61.57	$65.95	$60.31
(11)	Transmission (6) x (5)	$67.31	$47.45	$43.47	$39.28	$39.81	$40.25	$129.51	$91.89	$64.42	$53.67	$63.72	$68.26	$62.42
(12)	Distribution Station (7) x (5)	$68.28	$48.14	$44.10	$39.85	$40.38	$40.83	$131.39	$93.22	$65.35	$54.45	$64.65	$69.25	$63.32
(13)	Distribution Primary (8) x (5)	$69.84	$49.24	$45.11	$40.76	$41.31	$41.77	$134.39	$95.35	$66.85	$55.70	$66.13	$70.83	$64.77
(14)	Distribution Secondary (9) x (5)	$72.12	$50.85	$46.58	$42.09	$42.65	$43.13	$138.77	$98.46	$69.02	$57.51	$68.28	$73.14	$66.88

1/ Aurora Power Supply Model 2009 to 2013
2/ Schedule 14. Based on 2009 Test Year Cost of Capital
3/ IPCo 2006 IRP Technical Appendix, p.53
4/ IPCo 2008 Loss Factor Study, Schedule 15

SCHEDULE 1

IDAHO POWER COMPANY
Marginal Cost Analysis 2009
Annual Generation Capacity Cost - Dollars/kW

(1)	Investment ($/kw) 1/	$339.12
(2)	General Plant Loading (1) x 1.09 2/	$368.77
(3)	Economic Carrying Charge Rate 3/	7.61%
(4)	A&G Loading .55% 4/	0.55%
(5)	Total Carrying Charge	8.16%
(6)	Annual Cost ($/kw) (2) x (5)	$30.09
(7)	Demand related fixed O&M 5/	$6.96
(8)	A&G loading (7) x 1.411 6/	$9.81
(9)	Marginal Demand Related Costs (6) + (8)	$39.91
	Working Capital	
(10)	Materials & Supplies (2) x 1.03%	$3.79
(11)	Revenue Requirement for Materials & Supplies (10) x 12.28%	$0.46
(12)	Total Marginal Demand Related Costs (9) + (11) rounded	$40.37
(13)	Adjusted for reserve margin (11%) 7/	**$45.00**

1/ Total Investment of Danskin CT1 $57,650,861 / 170 MW (Case No. IPC-E-08-01, Exhibit 2)

2/ Schedule 14. Average general plant loading 2004-2008

3/ Schedule 13. Based on 2009 Test Year Cost of Capital

4/ Average A & G expenses 2004 - 2008 applicable to plant related expenses, Schedule 14

5/ Estimated cost of a simple cycle combustion turbine , IPCo 2006 IRP Technical Appendix, p.57

6/ Average A & G expenses 2004 - 2008 applicable to non-plant related expenses, Schedule 14

7/ IPCO 2006 IRP p. 37

IDAHO POWER COMPANY
Marginal Cost Analysis 2009
Seasonalized Generation Capacity Marginal Costs

		(1)	(2)	(3)
	Month	**% Share of Total 1/**	**$/kw/year $45.00**	**Monthly Marginal Cost** (1) X (2)
(1)	**Jan**	0.00%		0.00
(2)	**Feb**	0.00%		0.00
(3)	**Mar**	0.00%		0.00
(4)	**Apr**	0.00%		0.00
(5)	**May**	19.04%		8.57
(6)	**Jun**	20.88%		9.39
(7)	**Jul**	22.55%		10.15
(8)	**Aug**	12.22%		5.50
(9)	**Sep**	14.27%		6.42
(10)	**Oct**	0.00%		0.00
(11)	**Nov**	0.28%		0.13
(12)	**Dec**	10.76%		4.84
(13)	**Sum**	100.00%		45.00

1/ G & T Assignment Factors Workpaper
Seasonalized based on average monthly share of peak hour deficiencies
for the five year period 2009-2013. Source: 2006 IRP Technical Appendix, p. 78

IDAHO POWER COMPANY
Marginal Cost Analysis 2009
Annual Transmission Marginal Costs
Dollars/kw

		Integration of New Resources	Planned System Expansion	Total
		(1)	(2)	(1) + (2)
(1)	Investment ($/kw)	$114.58	$1,841.30	
(2)	With General Plant Loading (1) x 1.09 1/	$124.60	$2,002.31	
(3)	Economic Carrying Charge Rate 2/	6.58%	6.58%	
(4)	A&G Loading .55% 3/	0.55%	0.55%	
(5)	Total Carrying Charge	7.13%	7.13%	
(6)	Annual Cost ($/kw) (2) x (5)	$8.88	$142.77	
(7)	Demand related O&M 4/	$6.69	$6.69	
(8)	With A&G loading (7) x 1.411 5/	$9.43	$9.43	
(9)	Marginal Demand Related Costs (6) + (8)	$18.31	$152.20	
	Working Capital			
(10)	Materials & Supplies (2) x 1.03%	$1.28	$20.56	
(11)	Revenue Requirement and Taxes for Materials & Supplies (10) x 12.28% 6/	$0.16	$2.52	
(12)	Total Marginal Demand Related Costs (9) + (10) + (11) Rounded	$18.47	$154.72	
(13)	Total Annual Transmission Marginal Costs (rounded)	**$18.00**	**$155.00**	**$ 173.00**

1/ Average general plant loading 2004 - 2008, Schedule 14
2/ Schedule 13. Based on 2009 Test Year Cost of Capital
3/ Average A & G expenses 2004 - 2008 applicable to plant related expenses, Schedule 14
4/ Average O& M 2004 - 2008 w/o accts. 565 & 567
5/ Average A & G expenses 2004 - 2008 applicable to non-plant related expenses, Schedule 14
6/ Schedule 14. Based on 2009 Test Year Cost of Capital

IDAHO POWER COMPANY
Marginal Cost Analysis 2009
Seasonalized Transmission Marginal Costs
Dollars / kW

		Integration of New Resources			Planned System Expansion			TOTAL
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Month	% Share of Total 1/	$/kw/year 2/ $18.00	Monthly Marginal Cost (1) X (2)	% Share of Total 3/	$/kw/year 4/ $155.00	Monthly Marginal Cost (1) X (2)	Monthly Marginal Cost (3) + (6)
(1)	Jan	0.00%		$0.00	5.71%		$8.85	8.85
(2)	Feb	0.00%		$0.00	4.37%		$6.77	6.77
(3)	Mar	0.00%		$0.00	5.44%		$8.43	8.43
(4)	Apr	0.00%		$0.00	3.07%		$4.76	4.76
(5)	May	19.04%		$3.43	11.97%		$18.55	21.98
(6)	Jun	20.88%		$3.76	12.94%		$20.06	23.82
(7)	Jul	22.55%		$4.05	14.82%		$22.97	27.02
(8)	Aug	12.22%		$2.20	12.45%		$19.30	21.50
(9)	Sep	14.27%		$2.57	11.59%		$17.96	20.53
(10)	Oct	0.00%		$0.00	5.71%		$8.85	8.85
(11)	Nov	0.28%		$0.05	6.15%		$9.53	9.58
(12)	Dec	10.76%		$1.94	5.77%		$8.94	10.88
(13)	Sum	100.00%		$18.00	100.00%		$155.00	173.00

1/ Seasonalized based on average monthly share of peak hour deficiencies
for the five year period 2009-2013. Source: 2006 IRP Technical Appendix, p. 78
G & T Assignment Factors Workpaper
2/ Schedule 3, page 1 of 2
3/ Seasonalized based on monthly share of peak hour load growth between 2009 and 2018
Source: 2006 IRP Technical Appendix p. 25 - 36
G & T Assignment Factors Workpaper
4/ Schedule 3, page 1 of 2

IDAHO POWER COMPANY
Marginal Cost Analysis 2009
Derivation of Marginal Distribution Substation Investment

(1)	Investment in Load Related Additions to Distribution Substation Plant, 2009 - 2013 (Thousands of 2008 Dollars)	$54,091
(2)	Additions to Distribution Peak Load 2009 - 2013 in MW	270
(3)	Marginal Investment in Load Related Distribution Substation Facilities per Kilowatt (2008 Dollars) (1) / (2)	**$200.41**

IDAHO POWER COMPANY
Marginal Cost Analysis 2009
Distribution Substation O&M Expenses per kW of Distribution Peak Load
(2008 dollars)

	Year	Total Distribution Substation Expenses 1/ (Thousand (Dollars)	Distribution Peak Load (MW)	Substation Expenses Per kW of Peak Load (Dollars) (1) / (2)
		(1)	(2)	(3)
(1)	2009	$5,095	3,309	1.54
(2)	2010	$4,979	3,378	1.47
(3)	2011	$4,904	3,441	1.43
(4)	2012	$4,963	3,504	1.42
(5)	2013	$5,040	3,579	1.41

(6) Estimated Annual Distribution Substation O&M Expenses for the Planning Period **$1.45 per kw**

1/ Distribution substation expenses are total substation O&M expenses (Accounts 582 and 592) and overheads allocated to substation O&M expenses. Operation overheads (Accounts 580 and 588) and maintenance overheads (Account 590) were allocated to substations based on the relative importance of these expenses in total operation and maintenance (excluding overhead), respectively.

IDAHO POWER COMPANY
Marginal Cost Analysis 2009
Distribution Facilities Investment by Rate Class

Rate 01	$542
Rate 07	$407
Rate 09P	$327
Rate 09S	$401
Rate 19P	$158
Rate 24	$396
Rates 15,41,42	$244
Rate 40	$221

IDAHO POWER COMPANY
Marginal Cost Analysis 2009
Distribution Facilities O&M Expenses per kW
(2008 dollars)

	Year	Distribution Facilities O&M Expenses 1/	Total Peak Distribution Loads	O&M Expense Per kw	O&M Expense Per kW of Demand Secondary	O&M Expense Per kW of Demand Primary
		--(1000 Dollars)--	-- (MW)) --	---- (Dollars) ---- (1) / (2)	(2008 Dollars) .5 x (3)	(2008 Dollars) .5 x (3)
		(1)	(2)	(3)	(4)	(5)
(1)	2009	$24,088	3,309	$7.28	$3.64	$3.64
(2)	2010	$23,537	3,378	$6.97	$3.48	$3.48
(3)	2011	$23,184	3,441	$6.74	$3.37	$3.37
(4)	2012	$23,459	3,504	$6.70	$3.35	$3.35
(5)	2013	$23,826	3,579	$6.66	$3.33	$3.33
(6)	Est. Annual Distribution Facilities O&M Expenses for the Planning Period				$3.39	$3.39

(7) Estimated Annual Distribution Facilities O&M Expenses for a Primary Customer **$3.39**

(8) Estimated Distribution Facilities O&M Expense for a Secondary Customer: **$6.78**

1/ Distribution facilities expenses are total distribution O&M expenses excluding rents (Account 589), meter expenses (Accounts 586 and 597), street lighting expenses (Accounts 585 and 596), substation expenses (Accounts 582 and 592), expenses related to subtransmission, and overheads allocated to meters and street lighting, substation and subtransmission expenses. Operation overheads (Accounts 580 and 588) and maintenance overheads (Account 590) were allocated to facilities expenses based on the relative importance of these expenses in total operation and maintenance expenses (excluding overheads).

IDAHO POWER COMPANY
Marginal Cost Analysis 2009
SUMMARY OF INSTALLED METERS BY CLASS
(2008 dollars)

	Rate	Class	Investment
(1)	Rate 01	Residential	$128
(2)	Rate 07	Commercial	$238
(3)	Rate 09 - P	Commercial	$6,094
(4)	Rate 09 - S	Commercial	$281
(5)	Rate 09 - T	Commercial	$6,094
(6)	Rate 19 - P	Industrial	$7,303
(7)	Rate 19 - T	Industrial	$7,303
(8)	Rate 24	Irrigation	$347
(9)	Rates 41,42	Metered Lighting	$143

IDAHO POWER COMPANY
Marginal Cost Analysis 2009
Meter O&M Expense by Customer Class
(2008 dollars)

	Rate		Class	Weighting Factor	Annual Meter Expense Per Customer
					(1) x $12.80
				(1)	(2)
(1)	Residential Service	1		1.00	$12.80
(2)	Small General Service	7		1.86	23.81
(3)	Large General Service	9P	Primary	47.61	609.41
(4)	Large General Service	9S	Secondary	2.20	28.16
(5)	Large General Service	9T	Transmission	47.61	609.41
(6)	Uniform Rate - Industrial	19		57.05	730.24
(7)	Uniform Rate Industrial	19T	Transmission	57.05	730.24
(8)	Irrigation	24		2.71	34.69
(9)	Metered Lighting	41,42		1.12	14.34

IDAHO POWER COMPANY
Marginal Cost Analysis 2009
Meter O&M Expense per Weighted Customer
(2008 dollars)

	Year	Total Meter Operation Maintenance Expenses 1/ (Thousand Dollars)	Average Number of Customers	Weighted Average Number of Customers	Meter Expense Per Weighted Customer (Dollars)
				(2) x 1.22 2/	[(1) x 1000]/(3)
		(1)	(2)	(3)	(4)
(1)	2009	$8,338	492,435	600,771	$13.88
(2)	2010	$8,147	503,729	614,550	13.26
(3)	2011	$8,025	515,284	628,647	12.77
(4)	2012	$8,121	527,106	643,069	12.63
(5)	2013	$8,247	539,201	657,825	12.54

(6) Estimated Annual Weighted Meter O&M Expense for the Planning Period 3/ **$12.80**

1/ Total meter expenses are meter operation and maintenance expenses (Accounts 586 and 597) and overheads allocated to meters. Operation overheads (Accounts 580 and 588) and maintenance overheads (Account 590) were allocated to meters expense based on the relative importance of these expenses to total distribution O&M (excluding overhead).
2/ Schedule 6, page 4
3/ Average of 2009 - 2013

IDAHO POWER COMPANY
Marginal Cost Analysis 2009
Development of Electric Meter Weighting Factors

	Customer Class			Installed Meter Cost 2008	Weight	Actual Avg 2008 Number of Customers	Weighted Number of Customers	Meter O&M Weighting Factor
					(1) / 128.00		(2) x (3)	(4) / (3)
				(1)	(2)	(3)	(4)	(5)
(1)	Residential Service	1		$128.00	1.00	402,197	402,197	
(2)	Small General Service	7		$238.00	1.86	32,723	60,864	
(3)	Large General Service	9P	Primary	$6,094.00	47.61	159	7,551	
(4)	Large General Service	9S	Secondary	$281.00	2.20	28,920	63,623	
(5)	Large General Service	9T	Transmission	$6,094.00	47.61	2	95	
(6)	Uniform Rate - Industrial	19	P & S	$7,303.00	57.05	114	6,481	
(7)	Uniform Rate Industrial	19T	Transmission	$7,303.00	57.05	5	280	
(8)	Irrigation	24		$347.00	2.71	17,277	46,821	
(9)	Metered Lighting	41,42		$143.00	1.12	609	682	
						482,005	588,594	**1.22**

IDAHO POWER COMPANY
Marginal Cost Analysis 2009
Investment Cost of the Service Drop

Single Phase	$243
Three Phase	$334

	Rate 01	Rate 07	Rate 09-P	Rate 09-S	Rate 09 T	Rate 19	Rate 19 T	Rate 24	Rate 42
Percent Single Phase	96%	69%	n/a	75%	n/a	n/a	n/a	30%	88%
Percent Three Phase	4%	31%	n/a	25%	n/a	n/a	n/a	70%	12%

SCHEDULE 7

IDAHO POWER COMPANY
Marginal Cost Analysis 2009
Customer Accounts Expense by Customer Class
(2008 Dollars)

	Customer Class		Weighting Factor 1/	Annual Customer Accts Expense Per Customer
				$40.80 2/
			(1)	(2)
(1)	Residential Service	1	1	$40.80
(2)	Small General Service	7	1	$40.80
(3)	Large General Service	9P	1	$40.80
(4)	Large General Service	9S	1	$40.80
(5)	Large General Service	9T	1	$40.80
(6)	Uniform Rate - Industrial	19	26	$1,060.80
(7)	Uniform Rate Industrial	19T	26	$1,060.80
(8)	Irrigation	24	1	$40.80
(9)	Lighting	40,41,42	1	$40.80

1/ Schedule 8, page 3
2/ Schedule 8, page 2

IDAHO POWER COMPANY
Marginal Cost Analysis 2009
Customer Accounts Expense per Weighted Customer
(2008 dollars)

			2009 (1)	2010 (2)	2011 (3)	2012 (4)	2013 (5)
(1)	Customer Accounts Expenses (Thousand Dollars)		$21,667	$21,172	$20,854	$21,102	$21,432
(2)	Customers 1/		492,435	503,729	515,284	527,106	539,201
(3)	Weighted Customers Weighting Factor =	1.01	497,360	508,767	520,437	532,377	544,593
(4)	Expense per Weighted Customer (Dollars) [(1) / (3)] x 1000		$43.57	$41.61	$40.07	$39.64	$39.35
(5)	Estimated Annual Expense Per Customer For the Planning Period	2/	---------------	--------------	**$40.80**	-------------	-------------

1/ Average number of customers.
2/ Average of 2009 - 2013

IDAHO POWER COMPANY
Marginal Cost Analysis 2009
2008 Customer Accounts Expense by Rate Class

	Account 901		Account 902	Account 903	Account 904	Account 905		Total Expense	Customers	Cost Per Customer	Customer Weights	Weighted Customers
	Total #902 - #905	Allocated Expense				Total #902 - #904	Allocated Expense					
Residential	35,153,926	287,721	4,629,769	9,756,176	3,191,018	17,576,963	394	17,865,078	402,197	44.42	1	402,197
Commercial 7	2,482,439	20,318	408,642	782,011	50,567	1,241,220	28	1,261,565	32,723	38.55	1	32,723
Commercial 9	2,720,053	22,263	398,131	694,047	267,848	1,360,026	31	1,382,319	29,080	47.53	1	29,080
Uniform Contracts (19)	264,695	2,166	47,721	0	84,627	132,348	3	134,517	119	1,135.16	26	3,081
Irrigation	980,597	8,026	266,699	413,483	(189,883)	490,299	11	498,335	17,277	28.84	1	17,277
Unmetered General Service	93,418	765	0	46,474	235	46,709	1	47,475	1,917	24.76	1	1,917
Municipal Street Lighting	11,478	94	0	5,739	0	5,739	0	5,833	331	17.64	0	0
Traffic Control Lighting	13,486	110	0	6,743	0	6,743	0	6,854	278	24.64	1	278
Special Contracts	2,404	20	1,202	0	0	1,202	0	1,222	4	305.43	7	28
TOTAL	41,722,497	341,482	5,752,164	11,704,673	3,404,412	20,861,249	468	21,203,199	483,926			486,582

Weighting Factor:	1.01

IDAHO POWER COMPANY
Marginal Cost Analysis 2009
Customer Service and Informational Expense
(2008 dollars)

		2009	2010	2011	2012	2013
		(1)	(2)	(3)	(4)	(5)
(1)	Customer Service and Informational Expenses (Thousand Dollars)	$10,971	$10,794	$10,681	$10,770	$10,887
(2)	Customers 1/	492,435	503,729	515,284	527,106	539,201
(3)	Weighted Number of Customers (2) x 1	492,435	503,729	515,284	527,106	539,201
(4)	Expense Per Customer (2008 Dollars) [(1) / (3)] x 1000	$22.28	$21.43	$20.73	$20.43	$20.19
(5)	Estimated Annual Expense Per Customer For the Planning Period 2/	----------------	-------------	**$21.00**	-------------	-------------

1/ Average number of customers
2/ Average of 2009 - 2013

IDAHO POWER COMPANY
Marginal Cost Analysis 2009
Annual Distribution Substation Unit Costs
(2008 dollars)

			Distribution Substation
(1)	Marginal Investment per kW	1/	$200.41
(2)	With General Plant Loading (1) x 1.09	2/	217.93
(3)	Annual Economic Carrying Charge Related to Capital Investment	3/	7.01%
(4)	A&G Loading (Plant Related)	4/	0.55%
(5)	Total Annual Carrying Charge (3) + (4)		7.56%
(6)	Annualized Costs (2) x (5)		$16.48
(7)	Demand Related O&M Expenses	5/	1.45
(8)	With A&G Loading (7) x 1.410 (Non-Plant Related)	6/	2.04
(9)	Demand-Related Cost (6) + (8)		$18.52
	Working Capital		
(10)	Material and Supplies (2) x 1.03%	7/	$2.24
(11)	Total Working Capital (10)		$2.24
(12)	Revenue Requirement for Working Capital (11) x 12.28%	8/	0.27
(13)	Total Demand Related Costs (9) + (12)		$18.80
(14)	Total Annual Marginal Cost per kW		**$18.80**

1/ Schedule 4, page 1
2/ Schedule 14
3/ Schedule 13
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IDAHO POWER COMPANY
Marginal Cost Analysis 2009
Derivation of Annual Distribution Facilities Unit Costs

			Residential	Commercial			Industrial	Irrigation	Lighting	Lighting
			Rate 01	Rate 07	Rate 09 - P	Rate 09 - S	Rate 19	Rate 24 & 25	Rates 15,41,42	Rate 40
(1)	Marginal Investment per kw	1/	$542.23	$406.64	$326.68	$401.34	$157.56	$396.15	$243.54	$221.44
(2)	With General Plant Loading (1) x 1.09	2/	589.64	442.20	355.25	436.44	171.33	430.79	264.84	240.80
(3)	Annual Economic Carrying Charge Related to Capital Investment	3/	7.01%	7.01%	7.01%	7.01%	7.01%	7.01%	7.01%	7.01%
(4)	A&G Loading (plant-related)	4/	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%
(5)	Total Annual Carrying Charge (3) + (4)		7.56%	7.56%	7.56%	7.56%	7.56%	7.56%	7.56%	7.56%
(6)	Annualized Costs (2) x (5)		$44.58	$33.43	$26.86	$32.99	$12.95	$32.57	$20.02	$18.20
(7)	Facilities Investment O&M Expenses	5/	$6.78	$6.78	$3.39	$6.78	$3.39	$6.78	$6.78	$6.78
(8)	With A&G Loading [(7)] x 1.4102 (non plant related)	6/	$9.56	$9.56	$4.78	$9.56	$4.78	$9.56	$9.56	$9.56
(9)	Facilities Investment Cost (6) + (8)		$54.14	$42.99	$31.64	$42.56	$17.73	$42.13	$29.58	$27.77
	Working Capital									
(10)	Materials and Supplies (2) x 1.03%	7/	$6.05	$4.54	$3.65	$4.48	$1.76	$4.42	$2.72	$2.47
(11)	Total Working Capital		$6.05	$4.54	$3.65	$4.48	$1.76	$4.42	$2.72	$2.47
(12)	Revenue Requirement for Working Capital (12) x 12.28%	8/	$0.74	$0.56	$0.45	$0.55	$0.22	$0.54	$0.33	$0.30
(13)	Total Facilities Investment Costs (9) + (12)		$54.88	$43.55	$32.09	$43.11	$17.95	$42.67	$29.92	$28.07
(14)	Total Annual Marginal Cost per kw		**$54.88**	**$43.55**	**$32.09**	**$43.11**	**$17.95**	**$42.67**	**$29.92**	**$28.07**

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SCHEDULE 11

IDAHO POWER COMPANY
Marginal Cost Analysis 2009
Computation of Customer Related Marginal Unit Costs
(2008 dollars)

		Residential	Commercial				Industrial		Irrigation	Metered Lighting	Unmetered Lighting
		Rate 01	Rate 07	Rate 09 - P	Rate 09 - S	Rate 09 - T	Rate 19	Rate 19 - T	Rate 24	Rates 41,42	Rate 40
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
(1) Meter Investment	1/	$128.00	$238.00	$6,094.00	$281.00	$6,094.00	$7,303.00	$7,303.00	$347.00	$143.00	$0.00
(2) Service Drop	2/	$247.00	$271.00	$0.00	$266.00	$0.00	$0.00	$0.00	$307.00	$243.30	$0.00
(3) With General Plant Loading((1) + (2)) x 1.09	3/	$407.79	$553.51	$6,626.86	$594.83	$6,626.86	$7,941.57	$7,941.57	$711.19	$420.08	$0.00
(4)											
(5) Annual Economic Charge Related to											
(6) Capital Investment	4/	7.01%	7.01%	7.01%	7.01%	7.01%	7.01%	7.01%	7.01%	7.01%	7.01%
(7) A&G Loading (Plant Related)	5/	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%
(8) Total (5) + (7)		7.56%	7.56%	7.56%	7.56%	7.56%	7.56%	7.56%	7.56%	7.56%	7.56%
(9)											
(10) Annualized Costs (3) x (8)		$30.83	$41.85	$500.99	$44.97	$500.99	$600.39	$600.39	$53.77	$31.76	$0.00
(11)											
(12) Meter O&M Expense	6/	$12.80	$23.81	$609.41	$28.16	$609.41	$730.24	$730.24	$34.69	$14.34	$0.00
(13) Customer Accounts Expenses	7/	$40.80	$40.80	$40.80	$40.80	$40.80	$1,060.80	$1,060.80	$40.80	$40.80	$40.80
(14) Customer Service and Informational Expenses	8/	$21.00	$21.00	$21.00	$21.00	$21.00	$21.00	$21.00	$21.00	$21.00	$21.00
(15) With A&G Loading [(12)+(13)+(14)] x 1.4102	9/	105.20	120.73	946.54	126.86	946.54	2555.34	2555.34	136.07	107.37	87.15
(16) (Non-Plant Related)											
(17)											
(18) Customer Related Cost (10) + (15)		$136.03	$162.57	$1,447.53	$171.83	$1,447.53	$3,155.72	$3,155.72	$189.84	$139.13	$87.15
(19)											
(20) Working Capital											
(21) Materials and Supplies (3) x 1.03%	10/	$4.19	$5.68	$68.03	$6.11	$68.03	$81.53	$81.53	$7.30	$4.31	$0.00
(22) Revenue Requirement for Working Capital											
(23) [(21) x 12.28%	11/	$0.51	$0.70	$8.35	$0.75	$8.35	$10.01	$10.01	$0.90	$0.53	$0.00
(24)											
(25) Total Customer Related Costs (18) + (23)		$136.54	$163.27	$1,455.89	$172.58	$1,455.89	$3,165.74	$3,165.74	$190.73	$139.66	$87.15
(26)											
(27) Total Annual Marginal Unit Cost		**$136.54**	**$163.27**	**$1,455.89**	**$172.58**	**$1,455.89**	**$3,165.74**	**$3,165.74**	**$190.73**	**$139.66**	**$87.15**

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IDAHO POWER COMPANY
Marginal Cost Analysis 2009
Economic Carrying Charges

(1)	Combustion Turbine	7.61%
(2)	Transmission	6.58%
(3)	Distribution Substation	7.01%
(4)	Distribution Facilities	7.01%
(5)	Meters	7.01%

IDAHO POWER COMPANY
Marginal Cost Analysis 2009
Summary of Loaders

General Plant Loading	1.09
A&G Loading	
Plant-Related	0.55%
Non-Plant Related	1.410
Revenue Requirement for Working Capital & Fuel Inventory	12.28%
Materials and Supplies	1.03%

IDAHO POWER COMPANY
Marginal Cost Analysis 2009
Loss Factors

DEMAND

	Served at		
Plant from	Trans-mission	Primary	Secondary
Generation & Transmission	1.055	1.100	1.130
Distribution Substation	-----	1.043	1.071
Primary	-----	1.033	1.061
Secondary	-----	-----	1.027

ENERGY

	Served at			
Plant from	Trans-mission	Distribution Station	Primary	Secondary
Generation	1.035	1.050	1.074	1.109

IDAHO POWER COMPANY
Marginal Cost Analysis 2009
Marginal Unit Cost By Class
(2009 Dollars)

Description	(B) RESIDENTIAL (1)	(C) GEN SRV (7)	(D) GEN SRV SECONDARY (9-S)	(E) GEN SRV PRIMARY (9-P)	(G) AREA LIGHTING (15)	(I) LG POWER PRIMARY (19-P)	(J) LG POWER TRANS (19-T)	(K) IRRIGATION SECONDARY (24-S)	(L) UNMETERED GEN SERVICE (40)	(M) MUNICIPAL ST LIGHT (41)	(N) TRAFFIC CONTROL (42)
Demand Related Marginal Unit Cost											
Generation ($/Peak kW)											
January	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
February	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
March	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
April	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
May	$8.57	$8.57	$8.57	$8.57	$8.57	$8.57	$8.57	$8.57	$8.57	$8.57	$8.57
June	$9.39	$9.39	$9.39	$9.39	$9.39	$9.39	$9.39	$9.39	$9.39	$9.39	$9.39
July	$10.15	$10.15	$10.15	$10.15	$10.15	$10.15	$10.15	$10.15	$10.15	$10.15	$10.15
August	$5.50	$5.50	$5.50	$5.50	$5.50	$5.50	$5.50	$5.50	$5.50	$5.50	$5.50
September	$6.42	$6.42	$6.42	$6.42	$6.42	$6.42	$6.42	$6.42	$6.42	$6.42	$6.42
October	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
November	$0.13	$0.13	$0.13	$0.13	$0.13	$0.13	$0.13	$0.13	$0.13	$0.13	$0.13
December	$4.84	$4.84	$4.84	$4.84	$4.84	$4.84	$4.84	$4.84	$4.84	$4.84	$4.84
Total	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00
Transmission ($/Peak kW)											
January	$8.85	$8.85	$8.85	$8.85	$8.85	$8.85	$8.85	$8.85	$8.85	$8.85	$8.85
February	$6.77	$6.77	$6.77	$6.77	$6.77	$6.77	$6.77	$6.77	$6.77	$6.77	$6.77
March	$8.43	$8.43	$8.43	$8.43	$8.43	$8.43	$8.43	$8.43	$8.43	$8.43	$8.43
April	$4.76	$4.76	$4.76	$4.76	$4.76	$4.76	$4.76	$4.76	$4.76	$4.76	$4.76
May	$21.98	$21.98	$21.98	$21.98	$21.98	$21.98	$21.98	$21.98	$21.98	$21.98	$21.98
June	$23.82	$23.82	$23.82	$23.82	$23.82	$23.82	$23.82	$23.82	$23.82	$23.82	$23.82
July	$27.02	$27.02	$27.02	$27.02	$27.02	$27.02	$27.02	$27.02	$27.02	$27.02	$27.02
August	$21.50	$21.50	$21.50	$21.50	$21.50	$21.50	$21.50	$21.50	$21.50	$21.50	$21.50
September	$20.53	$20.53	$20.53	$20.53	$20.53	$20.53	$20.53	$20.53	$20.53	$20.53	$20.53
October	$8.85	$8.85	$8.85	$8.85	$8.85	$8.85	$8.85	$8.85	$8.85	$8.85	$8.85
November	$9.58	$9.58	$9.58	$9.58	$9.58	$9.58	$9.58	$9.58	$9.58	$9.58	$9.58
December	$10.88	$10.88	$10.88	$10.88	$10.88	$10.88	$10.88	$10.88	$10.88	$10.88	$10.88
Total	$172.97	$172.97	$172.97	$172.97	$172.97	$172.97	$172.97	$172.97	$172.97	$172.97	$172.97
Distribution											
Distribution Substation ($/Peak kW)	$18.80	$18.80	$18.80	$18.80	$18.80	$18.80	$0.00	$18.80	$18.80	$18.80	$18.80
Distribution Facilities Investment ($/Peak kW)	$54.88	$43.55	$43.11	$32.09	$29.92	$17.95	$0.00	$42.67	$28.07	$29.92	$29.92
Energy Related Marginal Unit Cost											
Generation Energy Related ($/MWh)											
January	$65.03	$65.03	$65.03	$65.03	$65.03	$65.03	$65.03	$65.03	$65.03	$65.03	$65.03
February	$45.85	$45.85	$45.85	$45.85	$45.85	$45.85	$45.85	$45.85	$45.85	$45.85	$45.85
March	$42.00	$42.00	$42.00	$42.00	$42.00	$42.00	$42.00	$42.00	$42.00	$42.00	$42.00
April	$37.95	$37.95	$37.95	$37.95	$37.95	$37.95	$37.95	$37.95	$37.95	$37.95	$37.95
May	$38.46	$38.46	$38.46	$38.46	$38.46	$38.46	$38.46	$38.46	$38.46	$38.46	$38.46
June	$38.89	$38.89	$38.89	$38.89	$38.89	$38.89	$38.89	$38.89	$38.89	$38.89	$38.89
July	$125.13	$125.13	$125.13	$125.13	$125.13	$125.13	$125.13	$125.13	$125.13	$125.13	$125.13
August	$88.78	$88.78	$88.78	$88.78	$88.78	$88.78	$88.78	$88.78	$88.78	$88.78	$88.78
September	$62.24	$62.24	$62.24	$62.24	$62.24	$62.24	$62.24	$62.24	$62.24	$62.24	$62.24
October	$51.86	$51.86	$51.86	$51.86	$51.86	$51.86	$51.86	$51.86	$51.86	$51.86	$51.86
November	$61.57	$61.57	$61.57	$61.57	$61.57	$61.57	$61.57	$61.57	$61.57	$61.57	$61.57
December	$65.95	$65.95	$65.95	$65.95	$65.95	$65.95	$65.95	$65.95	$65.95	$65.95	$65.95
Customer Related Marginal Unit Cost ($/Cust.)	$136.54	$163.27	$172.58	$1,455.89	$0.00	$3,165.74	$3,165.74	$190.73	$87.15	$139.66	$139.66

Idaho Power/803
Witness: Timothy E. Tatum

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Timothy E. Tatum
Summary of Marginal Costs by Customer Class

July 31, 2009

IDAHO POWER COMPANY
Marginal Cost Analysis 2009
Marginal Cost By Class - OREGON JURISDICTION
(2009 Dollars)

Line	Description	(A) TOTAL SYSTEM	(B) RESIDENTIAL (1)	(C) GEN SRV (7)	(D) GEN SRV SECONDARY (9-S)	(E) GEN SRV PRIMARY (9-P)	(F) AREA LIGHTING (15)	(G) LG POWER PRIMARY (19-P)	(H) LG POWER TRANS (19-T)	(I) IRRIGATION SECONDARY (24-S)	(J) UNMETERED GEN SERVICE (40)	(K) MUNICIPAL ST LIGHT (41)	(L) TRAFFIC CONTROL (42)
1													
2	Current Revenue	$32,433,692	$11,262,377	$1,176,138	$6,331,332	$654,786	$98,625	$6,712,141	$3,243,600	$2,846,148	$772	$106,979	$794
3													
4	Demand Related Marginal Cost												
5													
6	Generation	$5,368,907	$1,681,622	$160,628	$942,951	$119,727	$519	$1,078,999	$563,709	$819,581	$75	$995	$100
7	Transmission	$19,619,842	$6,550,472	$578,264	$3,633,896	$464,462	$3,144	$4,156,037	$1,873,309	$2,353,531	$288	$6,053	$385
8	Distribution	$9,658,948	$4,441,166	$280,793	$1,812,158	$171,415	$5,820	$1,102,323	$0	$1,833,817	$156	$11,191	$110
9													
10	Energy Related Marginal Cost												
11	Generation Energy Related	$46,251,305	$13,587,114	$1,187,823	$7,954,222	$1,055,870	$28,374	$11,838,944	$5,800,384	$4,741,513	$863	$55,044	$1,155
12													
13	Customer Related Marginal Cost	$2,877,137	$1,831,719	$489,644	$230,216	$7,279	$0	$18,994	$6,595	$289,732	$261	$1,857	$838
14													
15	Total Functionized Revenue Requirement												
16	Generation												
17	Demand-Related	$8,339,392	$2,612,022	$249,500	$1,464,663	$185,969	$806	$1,675,983	$875,596	$1,273,036	$116	$1,546	$156
18	Energy-Related	$12,854,145	$3,776,125	$330,119	$2,210,634	$293,447	$7,886	$3,290,275	$1,612,040	$1,317,759	$240	$15,298	$321
19													
20	Transmission	$3,983,187	$1,329,866	$117,398	$737,747	$94,294	$638	$843,751	$380,316	$477,810	$58	$1,229	$78
21													
22	Distribution												
23	Demand-Related	$10,919,664	$5,020,841	$317,443	$2,048,686	$193,788	$6,579	$1,246,201	$0	$2,073,173	$176	$12,652	$124
24	Customer-Related												
25	Allocated	$3,242,463	$2,064,303	$551,817	$259,448	$8,204	$0	$21,406	$7,433	$326,520	$295	$2,093	$944
26	Direct Assignment	$423,842	$194,523	$43,486	$19,343	$73	$60,306	$87	$30	$22,027	$44	$83,837	$87
27													
28	Total	$39,762,693	$14,997,679	$1,609,763	$6,740,522	$775,775	$76,215	$7,077,704	$2,875,415	$5,490,325	$929	$116,655	$1,710
29													
30	Revenue Difficiency	$7,329,001	$3,735,302	$433,625	$409,190	$120,989	($22,410)	$365,563	($368,185)	$2,644,177	$157	$9,676	$916
31													
32	% Increase Required	22.60%	33.17%	36.87%	6.46%	18.48%	-22.72%	5.45%	-11.35%	92.90%	20.34%	9.04%	115.40%
33													

Idaho Power Company
Marginal Cost Analysis 2009
2009 TY Revenue Requirement per Billing Component - OREGON JURISDICTION

**** * * RESIDENTIAL SERVICE - SCHEDULE 1 * * ****

FUNCTION	(A) REVENUE	(B) BILLING UNITS	(C) UNIT COSTS ($/EACH)	(D) SUMMER ($/KWH)	(E) NON-SUMMER ($/KWH)	(F) SERVICE ($/CUST/MO)
GENERATION						
DEMAND - Summer	$1,506,493.48	43,876,537	0.03433	0.03433		
DEMAND - Non-Summer	$1,105,528.07	154,682,385	0.00715		0.00715	
ENERGY - Summer	$1,204,245.37	43,876,537	0.02745	0.02745		
ENERGY - Non-Summer	$2,571,879.99	154,682,385	0.01663		0.01663	
TRANSMISSION						
DEMAND	$1,329,865.56	198,558,922	0.00670	0.00670	0.00670	
DISTRIBUTION	$5,020,840.65	198,558,922	0.02529	0.02529	0.02529	
CUSTOMERS (BILLINGS)	$2,258,826.35	160,983	14.03145			14.03145
TOTALS	$14,997,679.47			0.09377	0.05576	14.03145

**** * * SMALL GENERAL SERVICE - SCHEDULE 7 * * ****

FUNCTION	(A) REVENUE	(B) BILLING UNITS	(C) UNIT COSTS ($/EACH)	(D) SUMMER ($/KWH)	(E) NON-SUMMER ($/KWH)	(F) SERVICE ($/CUST/MO)
GENERATION						
DEMAND - Summer	$159,330.13	4,280,444	0.03722	0.03722		
DEMAND - Non-Summer	$90,169.58	12,920,608	0.00698		0.00698	
ENERGY - Summer	$116,989.49	4,280,444	0.02733	0.02733		
ENERGY - Non-Summer	$213,129.80	12,920,608	0.01650		0.01650	
TRANSMISSION						
DEMAND	$117,398.15	17,201,052	0.00683	0.00683	0.00683	
DISTRIBUTION	$317,442.94	17,201,052	0.01845	0.01845	0.01845	
CUSTOMERS (BILLINGS)	$595,302.56	35,988	16.54179			16.54179
TOTALS	$1,609,762.66			0.08983	0.04875	16.54179

Idaho Power Company
Marginal Cost Analysis 2009
2009 TY Revenue Requirement per Billing Component - OREGON JURISDICTION

**** * * LARGE GENERAL SERVICE - SCHEDULE 9 SECONDARY * * ****

FUNCTION	(A) REVENUE	(B) BILLING UNITS	(C) UNIT COSTS ($/EACH)	(D) SUMMER ($/KW)	(E) NON-SUMMER ($/KW)	(F) SUMMER ($/KWH)	(G) NON-SUMMER ($/KWH)	(H) SERVICE ($/CUST/MO)	(I) BASIC ($/KW)
GENERATION									
DEMAND - Summer	$855,015.85	87,373	9.78586	9.78586					
DEMAND - Non-Summer	$609,647.50	290,238	2.10051		2.10051				
ENERGY - Summer	$716,542.47	26,659,239	0.02688			0.02688			
ENERGY - Non-Summer	$1,494,091.87	90,297,619	0.01655				0.01655		
TRANSMISSION									
DEMAND	$737,747.43	377,611	1.95372	1.95372	1.95372				
DISTRIBUTION	$2,048,686.38	530,106	3.86467						3.86467
CUSTOMERS (BILLINGS)	$278,790.98	16,008	17.41616					17.41616	
TOTALS	$6,740,522.48			11.73958	4.05423	0.02688	0.01655	17.41616	3.86467

**** * * LARGE GENERAL SERVICE - SCHEDULE 9 PRIMARY * * ****

FUNCTION	(A) REVENUE	(B) BILLING UNITS	(C) UNIT COSTS ($/EACH)	(D) SUMMER ($/KW)	(E) NON-SUMMER ($/KW)	(F) SUMMER ($/KWH)	(G) NON-SUMMER ($/KWH)	(H) SERVICE ($/CUST/MO)	(I) BASIC ($/KW)
GENERATION									
DEMAND - Summer	$107,413.22	9,271	11.58622	11.58622					
DEMAND - Non-Summer	$78,556.27	27,854	2.82024		2.82024				
ENERGY - Summer	$100,480.67	3,855,826	0.02606			0.02606			
ENERGY - Non-Summer	$192,966.34	12,321,447	0.01566				0.01566		
TRANSMISSION									
DEMAND	$94,294.37	37,125	2.53990	2.53990	2.53990				
DISTRIBUTION	$193,788.22	46,987	4.12433						4.12433
CUSTOMERS (BILLINGS)	$8,276.26	60	137.93771					137.93771	
TOTALS	$775,775.36			14.12612	5.36014	0.02606	0.01566	137.93771	4.12433

Idaho Power Company
Marginal Cost Analysis 2009
2009 TY Revenue Requirement per Billing Component - OREGON JURISDICTION

**** * * LARGE POWER - SCHEDULE 19 PRIMARY * * ****

FUNCTION	(A) REVENUE	(B) BILLING UNITS	(C) UNIT COSTS ($/EACH)	(D) SUMMER ($/KW)	(E) NON-SUMMER ($/KW)	(F) SUMMER ($/KWH)	(G) NON-SUMMER ($/KWH)	(H) SERVICE ($/CUST/MO)	(I) BASIC ($/KW)
GENERATION									
DEMAND - Summer	$819,167.47	88,078	9.30045	9.30045					
DEMAND - Non-Summer	$856,815.84	243,179	3.52340		3.52340				
ENERGY - Summer	$1,214,208.14	48,330,793	0.02512			0.02512			
ENERGY - Non-Summer	$2,076,066.52	133,133,212	0.01559				0.01559		
TRANSMISSION									
DEMAND	$843,751.49	331,257	2.54712	2.54712	2.54712				
DISTRIBUTION	$1,246,201.11	358,534	3.47583						3.47583
CUSTOMERS (BILLINGS)	$21,493.27	72	298.51764					298.51764	
TOTALS	$7,077,703.83			11.84757	6.07051	0.02512	0.01559	298.51764	3.47583

**** * * LARGE POWER - SCHEDULE 19 TRANSMISSION * * ****

FUNCTION	(A) REVENUE	(B) BILLING UNITS	(C) UNIT COSTS ($/EACH)	(D) SUMMER ($/KW)	(E) NON-SUMMER ($/KW)	(F) SUMMER ($/KWH)	(G) NON-SUMMER ($/KWH)	(H) SERVICE ($/CUST/MO)
GENERATION								
DEMAND - Summer	$564,599.97	50,057	11.27903	11.27903				
DEMAND - Non-Summer	$310,995.56	125,452	2.47900		2.47900			
ENERGY - Summer	$719,565.46	27,981,572	0.02572			0.02572		
ENERGY - Non-Summer	$892,474.96	59,131,043	0.01509				0.01509	
TRANSMISSION								
DEMAND	$380,316.03	175,510	2.16692	2.16692	2.16692			
CUSTOMERS (BILLINGS)	$7,462.94	25	298.51764					298.51764
TOTALS	$2,875,414.93			13.44596	4.64592	0.02572	0.01509	298.51764

Idaho Power Company
Marginal Cost Analysis 2009
2009 TY Revenue Requirement per Billing Component - OREGON JURISDICTION

**** * * IRRIGATION - SCHEDULE 24 SECONDARY * * ****

(Production-related revenue and billing units are for June - September)

FUNCTION	(A) REVENUE	(B) BILLING UNITS	(C) UNIT COSTS ($/EACH)	(D) IN-SEASON ($/KW)	(E) OUT-SEASON ($/KW)	(F) IN-SEASON ($/KWH)	(G) OUT-SEASON ($/KWH)	(H) SERVICE ($/CUST/MO)
GENERATION								
DEMAND - In-Season	$958,520.84	111,758	8.57677	8.57677				
DEMAND - Out-Season	$314,514.79	67,570	4.65468		4.65468			
ENERGY - In-Season	$1,130,552.33	44,510,145	0.02540			0.02540		
ENERGY - Out-Season	$187,207.03	16,043,665	0.01167				0.01167	
TRANSMISSION								
DEMAND	$477,809.84	179,327	2.66446	2.66446	2.66446			
DISTRIBUTION	$2,073,173.00	179,327	11.56083	11.56083	11.56083			
CUSTOMERS (BILLINGS)	$348,547.12	18,229	19.12068					19.12068
TOTALS	$5,490,324.95			22.80205	18.87996	0.02540	0.01167	19.12068

Idaho Power/804
Witness: Timothy E. Tatum

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Timothy E. Tatum
Revenue Allocation Summary

July 31, 2009

Idaho Power Company
Before the Oregon Public Utility Commission
Revenue Allocation Summary
12 Months Ending December 31, 2009
Proformed Normalized Sales and Revenue

Line No.	Tariff Description	Rate Schedule No.	2009 Average Number of Customers	2009 Sales Normalized (kWh)	Proformed Normalized Revenue	Average Mills per kWh
	Uniform Tariff Schedules					
1	Residential Service	1	13,415	220,362,881	$ 11,262,377	51.11
2	Small General Service	7	2,999	19,087,766	1,176,138	61.62
3	Large General Service	9-S	1,334	129,779,060	6,331,332	48.79
4	Large General Service	9-P	5	17,340,865	654,786	37.76
5	Dusk/Dawn Lighting	15	-	470,308	98,625	209.70
6	Large Power Service	19-P	6	195,081,276	6,712,141	34.41
7	Large Power Service	19-T	2	90,310,412	3,243,600	35.92
8	Irrigation Service	24	1,519	67,154,213	2,846,148	42.38
9	Unmetered Service	40	3	14,306	772	53.96
10	Municipal Street Lighting	41	13	912,800	106,979	117.20
11	Traffic Control Lighting	42	6	19,144	794	41.48
12	*Total Oregon Rates*		19,302	740,533,033	32,433,692	43.80

Idaho Power Company
Before the Oregon Public Utility Commission
Revenue Allocation Summary
12 Months Ending December 31, 2009
Marginal Cost - Revenue Allocation Results

Line No.	Tariff Description	Rate Schedule No.	COS Percent Change	COS Revenue Change	Revenue Allocation at COS	Average Mills per kWh
	Uniform Tariff Schedules					
1	Residential Service	1	33.17%	$ 3,735,302	$ 14,997,679	68.06
2	Small General Service	7	36.87%	$ 433,625	$ 1,609,763	84.33
3	Large General Service	9-S	6.46%	$ 409,190	$ 6,740,522	51.94
4	Large General Service	9-P	18.48%	$ 120,989	$ 775,775	44.74
5	Dusk/Dawn Lighting	15	-22.72%	$ (22,410)	$ 76,215	162.05
6	Large Power Service	19-P	5.45%	$ 365,563	$ 7,077,704	36.28
7	Large Power Service	19-T	-11.35%	$ (368,185)	$ 2,875,415	31.84
8	Irrigation Service	24	92.90%	$ 2,644,177	$ 5,490,325	81.76
9	Unmetered Service	40	20.34%	$ 157	$ 929	64.94
10	Municipal Street Lighting	41	9.04%	$ 9,676	$ 116,655	127.80
11	Traffic Control Lighting	42	115.40%	$ 916	$ 1,710	89.34
12	*Total Oregon Rates*		22.60%	$ 7,329,001	39,762,693	53.69

Idaho Power Company
Before the Oregon Public Utility Commission
Revenue Allocation Summary
12 Months Ending December 31, 2009
First Pass Revenue Allocation

Line No.	Tariff Description	Rate Schedule No.	First Pass Percent Change	First Pass Revenue Change	First Pass Revenue Allocation
	Uniform Tariff Schedules				
1	Residential Service	1	33.17%	$ 3,735,302	$ 14,997,679
2	Small General Service	7	36.87%	433,625	$ 1,609,763
3	Large General Service	9-S	6.46%	409,190	$ 6,740,522
4	Large General Service	9-P	18.48%	120,989	$ 775,775
5	Dusk/Dawn Lighting	15	0.00%	-	$ 98,625
6	Large Power Service	19-P	5.45%	365,563	$ 7,077,704
7	Large Power Service	19-T	0.00%	-	$ 3,243,600
8	Irrigation Service	24	40.30%	1,146,861	$ 3,993,009
9	Unmetered Service	40	20.34%	157	$ 929
10	Municipal Street Lighting	41	9.04%	9,676	$ 116,655
11	Traffic Control Lighting	42	56.64%	450	$ 1,244
12	*Total Oregon Rates*		16.10%	6,221,814	38,655,506
13					
14					
15	Revenue Requirement Shortfall				$ 1,107,187

Idaho Power Company
Before the Oregon Public Utility Commission
Revenue Allocation Summary
12 Months Ending December 31, 2009
Final Revenue Allocation

Line No.	Tariff Description	Rate Schedule No.	Final Percent Change	Final Revenue Change	Final Revenue Allocation	Average Mills per kWh	Cost of Service Index
	Uniform Tariff Schedules						
1	Residential Service	1	37.34%	$ 4,205,529	$ 15,467,906	70.19	103.1%
2	Small General Service	7	41.16%	$ 484,096	$ 1,660,234	86.98	103.1%
3	Large General Service	9-S	9.80%	$ 620,528	$ 6,951,860	53.57	103.1%
4	Large General Service	9-P	22.19%	$ 145,312	$ 800,098	46.14	103.1%
5	Dusk/Dawn Lighting	15	0.00%	$ -	$ 98,625	209.70	129.4%
6	Large Power Service	19-P	8.75%	$ 587,472	$ 7,299,613	37.42	103.1%
7	Large Power Service	19-T	0.00%	$ -	$ 3,243,600	35.92	112.8%
8	Irrigation Service	24	44.69%	$ 1,272,055	$ 4,118,203	61.32	75.0%
9	Unmetered Service	40	24.11%	$ 186	$ 958	66.98	103.1%
10	Municipal Street Lighting	41	12.46%	$ 13,333	$ 120,312	131.81	103.1%
11	Traffic Control Lighting	42	61.55%	$ 489	$ 1,283	67.01	75.0%
12	*Total Oregon Rates*		22.60%	7,329,001	39,762,693	53.69	

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE _______

IN THE MATTER OF THE APPLICATION	)
OF IDAHO POWER COMPANY FOR	)
AUTHORITY TO INCREASE ITS RATES	)
AND CHARGES FOR ELECTRIC	)
SERVICE IN THE STATE OF OREGON.	)
	)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

COURTNEY WAITES

July 31, 2009

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

A. My name is Courtney Waites. I am employed by Idaho Power 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 educational 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 began my employment with Idaho Power 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 in responding to regulatory data requests pertaining to the finance scope of work. In 2006, I accepted my current position of 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 scope of your testimony in this proceeding?

A. My testimony will address the Company's rate design proposal for the residential customer class.

Q. What were your overall objectives in arriving at the proposed rate design for the customers taking Residential Service?

A. Under the direction of Company witness Michael Youngblood, the overall objectives with regard to rate spread and rate design were to (1) establish prices which primarily reflect the costs of the services provided, (2) have cost-based rate proposals designed to align with and encourage energy efficiency, and (3) provide consistency and continuity throughout the Company's service territory.

Q. Is your residential rate design proposal cost-based?

A. Yes. As Company witness Timothy Tatum has described in his testimony, the target revenue from the residential class is 103 percent of the class cost of service. My proposal implements the Company's objective by pricing the individual rate components closer to the cost of providing electric service, by implementing seasonal rates, and by increasing the differential between the first and second energy blocks.

Q. Does your proposal encourage increased energy efficiency?

A. Yes. My proposal supports the continuation of tiered rates and the implementation of season rates, both of which encourage customers to use less when prices are high.

Q. Is your proposal consistent with treatment of residential customers in Idaho?

A. Yes, it is. Although the rate designs are not identical, both the current Idaho residential rate design and the proposed Oregon residential rate design are cost-based and encourage energy efficiency through a seasonal, inverted tiered rate structure.

Q. What is the annual revenue requirement to be recovered from Residential Service customers taking service under Schedule 1?

A. The annual revenue requirement to be recovered from Residential Service customers taking service under Schedule 1 is $15,467,906, as shown on page 4 of Mr. Tatum's Exhibit No. 804.

Q. What are the major changes to the current rate design for Residential Service that you are proposing?

A. For Residential Service customers, the Company is proposing to increase the Service Charge, implement seasonal rates, and modify the energy block levels.

Q. Please describe the present rate structure for Residential Service under Schedule 1.

A. Residential Service customers currently taking service under Schedule 1 pay a monthly Service Charge of $5.25. Their energy charge is based upon a two-tier inverted block structure in which they pay a base Energy Charge of 3.7647¢ per kilowatt-hour ("kWh") for the first 300 kWh of energy used (the first block) and 4.7063¢ per kWh for all energy used over 300 kWh (the second block).

Q. Please describe your proposal to increase the Service Charge.

A. The Service Charge is intended to recover costs that do not vary with the amount of energy or capacity used. Historically, the Service Charge has been well below the unit cost, meaning that the Service Charge, from a cost of service standpoint, has under-collected the customer-related fixed costs associated with this rate component. In an attempt to meet the objective of moving the individual rate components closer to the cost of providing electric service, the Company is proposing to increase the Service Charge to $10.00 per month. The $10.00 per month Service Charge represents approximately 71 percent of the cost-of-service result of $14.03 shown at line 24 on page 2 of Mr. Tatum's Exhibit No. 803.

Q. Are there other reasons to increase the Service Charge?

A. Yes. In addition to meeting the Company's objective of moving rate components closer to the cost of service, increasing the Service Charge also helps remove the inherent financial disincentive for an electric utility to invest in energy efficiency programs.

Q. Please explain why there is an inherent financial disincentive for an electric utility to invest in energy efficiency programs.

When the Service Charge is well below the unit cost, more of the customer-related fixed costs are recovered through the volumetric charge, or Energy Charge. As the Company encourages energy efficiency and conservation, energy sales decline. Volumetric rates are generally based upon an assumed level of energy sales. Every reduction in energy sales yields a corresponding reduction in the utilities fixed cost recovery. In the Company's Idaho jurisdiction, the Service Charge for our residential customers is also below the unit cost; however, the Company has a Fixed Cost Adjustment mechanism in place to help recover fixed costs which may be under-collected as the Company encourages energy efficiency. Absent a Fixed Cost Adjustment mechanism in our Oregon service territory, it is important to have a Service Charge that better matches revenues with costs.

Q. You indicated the Company was proposing to implement seasonal rates. How are the seasons defined for the Company's residential pricing proposal?

A. The Company is proposing seasonal rates for two seasons, summer and non-summer. The summer season is defined as June 1 through August 31. The non-summer season is defined as September 1 through May 31. The proposed seasonal definition for the residential class is the same as that currently in place for our Schedule 7, Schedule 9, and Schedule 19 customers within Oregon as well as what is in place for our Schedule 1, Schedule 7, Schedule 9, and Schedule 19 customers throughout the rest of the Company's service territory.

Q. Please describe the Company's proposal for seasonal rates.

A. Keeping with the objectives of the rate design, the Company is proposing to implement seasonal rates to move the energy rate closer to the marginal cost of providing energy in the summer and non-summer months, to encourage energy efficiency for the residential customer class year-round, and to facilitate consistency throughout the Company's service territory by aligning the residential rate design in both the Company's Idaho and Oregon jurisdictions. For the summer months, the rate proposed for the first block is 6.8993¢ per kWh and 8.9691¢ per kWh for the second block. During the non-summer months, the proposed rates for the first and second blocks are 6.0303¢ per kWh and 7.5485¢ per kWh, respectively. This proposed rate design is shown on page 1 of Exhibit 901. In 2003, the differential between the average summer and non-summer marginal energy cost at generation level was 21 percent. In 2009, that differential has increased to 61 percent, emphasizing that the Company's highest power supply costs occur during the summer months. By setting the second block seasonal differential at approximately 19 percent, the Company is moving the energy rate closer to the marginal energy cost at generation level as well as encouraging energy efficiency for the residential class.

Q. Historically, the Oregon residential class peak was during the winter months while the Company's system peak occurred during the summer. Is the residential class still winter peaking?

A. Yes, it is.

Q. Why then is the Company proposing seasonal rates for the winter peaking residential class?

A. While the residential customer class' annual peak demand is forecast to occur in January, the residential class is expected to account for approximately 30 percent of the annual system peak. Furthermore, the residential class contribution to monthly peak demand levels throughout the summer is a significant driver of the Company's summer monthly *system* peaks. Likewise, the residential class' average energy use during the summer months of 2008 was 1,031 kWh, just below the 2008 annual average of 1,247 kWh. Although the Oregon residential customer class demand peaks in the winter months, the class still uses a significant amount of electricity in the summer when costs are highest for the Company to provide that power. Conversely, although the class' peak usage is in the winter months, this time of the year is less expensive for the Company to provide power. Thus, the price signal sent to customers by implementing seasonal rates is appropriate as it is representative of the actual costs to provide the power consumed. By implementing seasonal rates, the residential class will be sent a price signal more representative of actual costs.

Q. Please describe your proposal to modify the block levels.

A. Currently, customers taking service under Schedule 1 pay one rate for the first 300 kWh of energy used and a slightly higher rate for all energy used over 300 kWh year round. The Company is proposing to increase the cut-off for the first block of energy usage to 800 kWh.

Q. Why are you proposing to increase the size of the first block of energy use?

A. Inverted block rates are a mechanism for providing an incentive to customers to conserve energy by charging customers a higher rate for energy as the amount of energy usage increases. The Company's goal for the first energy block is to set it at a level that will cover a majority of customers' basic electric usage, or the usage that customers may not be able to reduce, for example usage from lighting and home appliances. Usage that falls in the second block, which is priced at a higher rate, is more likely discretionary usage. The Company has found that basic electric usage generally consists of more than 300 kWh per month, the current level of the first block. According to the Department of Energy ("DOE"), the end use consumption of only lighting and home appliances (which includes a refrigerator, electric range, electric oven, a microwave, and a water heater) is 512 kWh per month. Likewise, in their Housing Choice Voucher Program Guidebook, the U.S. Department of Housing and Urban Development ("HUD") estimates 700-850 kWh per month for the same basic electric usage.

Q. How did you determine that 800 kWh per month is the appropriate amount for the first block of energy usage?

A. First, I looked at the baseline load of the residential class. To estimate the baseline load, I looked at customers' loads during the spring and fall months, a time when it is reasonable to assume that neither an air conditioner nor a heater would be running or, if running, would have minimal usage. This would likely occur in May and October. The 2008 average usage for May and October was 987 kWh and 867 kWh, respectively. This baseline load estimate, which is slightly higher than that detailed by the DOE and HUD studies, would probably include a customer's lighting, basic home appliances (a refrigerator, range, oven microwave, and water heater) as well as other household appliances, such as clocks, stereos/radios, telephones, vacuum cleaners, televisions, and clothes washers and dryers.

Next, I looked at the average monthly residential customer energy usage. In the Company's Oregon jurisdiction, the average monthly energy usage for 2008 was approximately 1,247 kWh per month. In an effort to incent customers to conserve year-round, the Company is proposing to set the first block at approximately 60 percent of the average monthly energy usage for the Company's customers in Oregon, or 800 kWh. This level will also align with the basic electric usage studies performed by the DOE and HUD and the Company's baseline load estimates. Furthermore, adjusting the first consumption tier to 800 kWh will allow a large percentage of what might be considered basic electric usage to be priced at the lower rate while still providing an incentive to conserve.

Finally, setting the first block of energy at 800 kWh will meet another one of the Company's rate design objectives; it will facilitate consistency throughout our service territory for both customers and employees by aligning residential rate design in the Company's Oregon and Idaho jurisdictions.

Q. Are there any other changes to the proposed Schedule 1 rate design?

A. Yes. In addition to the changes I have discussed, the Company is proposing to increase the differential between the first and second energy blocks of both the summer and non-summer months. Currently, the differential between the first and second energy block is approximately 20 percent. In an effort to keep in line with the Company's objectives and move individual rate components closer to the cost of service, the Company is proposing to increase that differential to 30 percent in the summer months and 25 percent in the non-summer months. According to the cost of service results, the unit energy cost during the summer months is approximately 68 percent higher than the cost during the non-summer months (see page 2 of Mr. Tatum's Exhibit No. 803). Increasing the differential between the first and second energy blocks of both the summer and non-summer months will send a stronger price signal to customers encouraging the efficient use of energy, another objective of the Company.

Q. Please summarize the proposed charges for Residential Service customers taking service under Schedule 1.

A. The rate design proposal for Schedule 1 is included on page 1 of Exhibit 901. Under the proposed rate design, Schedule 1 customers would pay a $10.00 per month Service Charge. During the summer months, they would pay a base Energy Charge of 6.8993¢ per kWh for the first 800 kWh used and 8.9691¢ per kWh for all energy used over 800 kWh. During the non-summer months, they would pay 6.0303¢ per kWh for the first 800 kWh and 7.5485¢ per kWh for all energy used over 800 kWh.

Q. What impact does this rate design proposal have on Residential Service customers taking service under Schedule 1?

A. The typical monthly billing comparison for Residential Service customers taking service under Schedule 1 appears on page 1 of Exhibit No. 902. The overall increase required for the residential class is 37.34 percent (see page 4 of Mr. Tatum's Exhibit No. 804.) As shown on this exhibit, for customers whose usage equals or exceeds 800 kWh, the lower their monthly usage, the lower the overall percentage increase. A customer who uses 3,000 kWh will see an increase of 40.85 percent; however, a customer who uses 800 kWh will see an increase of 30.22 percent.

Q. Are you proposing any other changes to Schedule 1?

A. No.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Courtney Waites
Calculation of Revenue Impact − Schedule 1

July 31, 2009

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
General Rate Case
Filed July 31, 2009

Residential Service
Schedule 1

Line No	Description	(1) Usage Blocks	(2) Current Base Rate	(3) Current Base Revenue	(4) Adjusted Base Rate	(5) Adjusted Base Revenue	(6) Proposed Base Rate	(7) Proposed Base Revenue	(8) Revenue Difference	(9) Percent Change
1	Service Charge	160,983.1	5.25	845,161	5.25	845,161	10.00	1,609,831	764,670	90.48%
2	Minimum Charge	1,253.5	3.00	3,761	3.00	3,761	3.00	3,761	0	0.00%
3	Current Energy Blocks:									
4	0-300 kWh	44,027,050	0.037647	1,657,486	0.045117	1,986,368				
5	Over 300 kWh	154,531,872	0.047063	7,272,733	0.054533	8,427,087				
6	Total Energy	198,558,922		8,930,219		10,413,455				
7	Proposed Energy Blocks:									
8	Summer									
9	0-800 kWh	25,223,555					0.068993	1,740,249		
10	Over 800 kWh	15,849,871					0.089691	1,421,591		
11	Non-Summer									
12	0-800 kWh	78,733,322					0.060303	4,747,855		
13	Over 800 kWh	78,752,174					0.075485	5,944,608		
14	Total Energy	198,558,922						13,854,303	3,440,848	33.04%
15	Annual Power Cost Update	198,558,922	0.007470	1,483,235		0	0.000000	0	0	0.00%
16	Total Revenue			11,262,376		11,262,377		15,467,895	4,205,518	37.34%

Idaho Power/902
Witness: Courtney Waites

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Courtney Waites
Typical Monthly Billing Comparison – Schedule 1

July 31, 2009

Idaho Power Company
Typical Monthly Billing Comparison
State of Oregon
General Rate Case
Filed July 31, 2009

Residential Service
Schedule 1

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		Summer			Non-Summer			Avg Mth Cost -12 Mths		
Line No	Energy kWh	Current Revenue	Proposed Revenue	Percent Difference	Current Revenue	Proposed Revenue	Percent Difference	Current Revenue	Proposed Revenue	Percent Difference
1	0	5.25	10.00	90.48%	5.25	10.00	90.48%	5.25	10.00	90.48%
2	100	9.76	16.90	73.16%	9.76	16.03	64.24%	9.76	16.25	66.50%
3	200	14.27	23.80	66.78%	14.27	22.06	54.59%	14.27	22.50	57.67%
4	300	18.79	30.70	63.38%	18.79	28.09	49.49%	18.79	28.74	52.95%
5	400	24.24	37.60	55.12%	24.24	34.12	40.76%	24.24	34.99	44.35%
6	500	29.70	44.50	49.83%	29.70	40.15	35.19%	29.70	41.24	38.86%
7	600	35.15	51.40	46.23%	35.15	46.18	31.38%	35.15	47.49	35.11%
8	700	40.60	58.30	43.60%	40.60	52.21	28.60%	40.60	53.73	32.34%
9	800	46.06	65.19	41.53%	46.06	58.24	26.44%	46.06	59.98	30.22%
10	900	51.51	74.16	43.97%	51.51	65.79	27.72%	51.51	67.88	31.78%
11	1,000	56.96	83.13	45.94%	56.96	73.34	28.76%	56.96	75.79	33.06%
12	1,050	59.69	87.61	46.78%	59.69	77.11	29.18%	59.69	79.74	33.59%
13	1,100	62.42	92.10	47.55%	62.42	80.89	29.59%	62.42	83.69	34.08%
14	1,200	67.87	101.07	48.92%	67.87	88.43	30.29%	67.87	91.59	34.95%
15	1,300	73.32	110.04	50.08%	73.32	95.98	30.91%	73.32	99.50	35.71%
16	1,400	78.78	119.00	51.05%	78.78	103.53	31.42%	78.78	107.40	36.33%
17	1,500	84.23	127.97	51.93%	84.23	111.08	31.88%	84.23	115.30	36.89%
18	2,000	111.50	172.82	55.00%	111.50	148.82	33.47%	111.50	154.82	38.85%
19	2,500	138.76	217.66	56.86%	138.76	186.56	34.45%	138.76	194.34	40.05%
20	3,000	166.03	262.51	58.11%	166.03	224.31	35.10%	166.03	233.86	40.85%
21	4,000	220.56	352.20	59.68%	220.56	299.79	35.92%	220.56	312.89	41.86%
22	5,000	275.10	441.89	60.63%	275.10	375.28	36.42%	275.10	391.93	42.47%

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE _______

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE IN THE STATE OF OREGON.	)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

DARLENE NEMNICH

July 31, 2009

Q. Please state your name and business address.

A. My name is Darlene Nemnich. 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 "Company") as a Senior Pricing Analyst.

Q. Please describe your educational background as it relates to your position.

A. In May of 1979, I received a Bachelor of Arts degree in Business Administration with emphases in Finance and Economics from the College of Idaho in Caldwell, Idaho. In 2008, I attended the Center for Public Utilities course on public utility regulation.

Q. Please describe your business experience with Idaho Power.

A. In 1982, I was hired as an analyst in the Resource Planning Department. My primary duties were the calculation of avoided costs for cogeneration and small power production contracts and the calculation of costs of future generation resource options. In 1989, I moved to the Energy Services Department where I performed economic, financial, and statistical analyses to determine the cost-effectiveness of demand-side management programs. I stayed in that general area, designing, implementing, and evaluating programs until 2000, when I was promoted to Energy Efficiency Coordinator. In 2003, I was promoted to Energy Efficiency Leader where I managed the Company's demand-side management effort, including strategic planning, design, and development of programs, regulatory compliance, and overall management of the department. In 2006, I left the Company to pursue personal opportunities. In April 2008, I returned to the Company as a Senior Pricing Analyst in the Pricing and Regulatory Services Department. My duties as Senior Pricing

Analyst include the development of alternative pricing structures, analysis of the impact on customers of rate design changes, and the administration of the Company's tariffs.

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

A. My testimony will address the Company's rate design proposal for commercial and industrial customers taking service under Schedule 7, Small General Service; Schedule 9, Large General Service; and Schedule 19, Large Power Service.

Q. How did you arrive at the proposed rate design presented in this case?

A. The design of this rate proposal was accomplished through analyses and input from the Pricing and Regulatory Services Department and consultation with Company witness Gregory Said, the Company's Director of State Regulation, Company witness Michael Youngblood, the Company's Manager of Rate Design, Company witness Timothy Tatum, the Company's Manager of Cost of Service, the Company's field staff located in Oregon, and the Company's legal staff. For changes to specific service schedules, I also consulted with teams from many different departments within the Company, including Load Research, Customer Billing Support, Data Warehouse Management, Customer Relations and Energy Efficiency, and Customer Service.

Q. What are the Company's overall objectives with regard to its rate design strategy?

A. As Mr. Youngblood discusses in his testimony, the overall objectives with regard to rate spread and rate design are to (1) establish prices which primarily reflect the costs of the services provided, (2) have cost-based rate proposals designed to align with and encourage energy efficiency, and (3) provide consistency and continuity throughout the Company's service territory.

Q. In your rate design proposals, how do you accomplish the first objective: to establish prices which primarily reflect the costs of services provided?

A. The primary way that this objective is met is by moving rate components from their current levels toward the unit cost levels resulting from Mr. Tatum's cost-of-service analysis. This movement has generally emphasized increases in the demand and customer components as well as increases in the summer season. In addition, the time-of-use rate design proposals reflect that costs to the Company are higher in the summer and higher during certain hours of the day.

Q. In your rate design proposals how do you accomplish the second objective: to have cost-based rate proposals designed to align with and encourage energy efficiency?

A. The specific mechanisms included to encourage energy efficiency are inclining block rates for our Small General Service customers and seasonal rates. Time-of-use rates can also provide a load reduction as well as a load shifting signal. And, generally, the proposed rate designs for our Large General Service and Large Power Service customers provide lower overall increases for those customers who have higher load factors, thereby encouraging efficiency. These rate structures give customers the opportunity to manage their bills by reducing energy or shifting usage to less expensive time periods.

Q. In your rate design proposals, how do you accomplish the third objective: to provide consistency and continuity throughout the Company's service territory?

A. Where it makes sense, the rate design proposals align component structures and levels with similar tariffs in our Idaho territory. Tariff wording, where appropriate, is also aligned between the Idaho and Oregon schedules. In addition, for the commercial and industrial classes, there is an overall effort to align rate design, and, in some cases, rate component levels, across customer classes for customers taking service at similar voltage levels. These voltage levels are referred to as service levels. These relationships are discussed in more detail later in my testimony. Consistency and stability in the structure of the rate design and levels is maintained in order to ameliorate problems for customers who move from one schedule to another.

Q. What are the major changes to the current rate design you are proposing?

A. In addition to modifying the rate levels to reflect the proposed revenue requirement, I am proposing three rate design changes. First, for Schedule 7, Small General Service, I am proposing to add a block rate on the energy charge during the non-summer time period. This block rate will mirror the existing summer block rate and provide an energy efficiency incentive for customers using more than 300 kilowatt-hours ("kWh") during non-summer months. Second, in order to provide clear price signals and provide opportunities for customers to manage their electricity bills, I am proposing time-of-use rates for customers taking service under Schedule 9, Large General Service, at the Primary and Transmission levels. And third, for Schedule 19, Large Power Service, I am proposing to increase the differentials between the On-Peak, Mid-Peak, and Off-Peak Energy Charges during the summer and non-summer seasons. This will provide an increased incentive for customers to reduce or shift load during the summer months, the Company's most expensive time to provide power.

Q. Have you prepared any exhibits relating to your rate design testimony?

A. Yes. I am sponsoring the following exhibits relating to rate design:

1. Exhibit No. 1001, Calculation of Proposed Rates; and
2. Exhibit No. 1002, Typical Monthly Billing Comparisons.

Q. Please describe Exhibit No. 1001.

A. Exhibit No. 1001 indicates the rate calculations made, by billing component, for Service Schedules 7, 9, and 19 at the different service levels.

Q. Please describe Exhibit No. 1002.

A. Exhibit No. 1002 shows the impact on customers' bills of the proposed rate designs for Schedules 7, 9, and 19.

Q. How have you organized the discussion of your rate design proposals?

A. My testimony will address rate design proposals for Schedules 7, 9, and 19. I will also discuss the alignment and relationship between Schedule 9 and 19 as it impacts rate design.

<u>SMALL GENERAL SERVICE, SCHEDULE 7</u>

Q. What is the present rate structure for Small General Service under Schedule 7?

A. Schedule 7 is available to customers whose metered energy usage is 3,000 kWh or less per billing period for 10 or more billing periods during the most recent 12 billing periods and whose demand has not exceeded 30 kilowatts ("kW") more than once during the most recent 12 consecutive billing periods. Customers taking service under Schedule 7 pay a Service Charge of $6.55 per month for single-phase service and $13.10 per month for three-phase service. During the summer months, customers pay an Energy Charge of 5.2019¢ per kWh for the first 300 kWh used and 5.6919¢ per kWh for all usage over 300 kWh. During the non-summer months of September through May, customers pay 5.2019¢ per kWh for all kWh used. Demand is not billed for Schedule 7 customers. As of the end of 2008, Idaho Power had 2,463 customers taking service under Schedule 7.

Q. Please describe the rate design proposal for Schedule 7.

A. I am proposing to add an inverted block rate during the non-summer months for Schedule 7. This block rate is set at 300 kWh, which is the same level as the existing summer block rate on this Schedule.

Q. Why is the Company proposing to add a block rate in the non-summer months?

A. By setting a block rate in non-summer months, the Company gives a price signal to encourage customers to use electricity efficiently and wisely. Customers who work towards reducing their monthly kWh usage can expect a larger reduction on their bill when they conserve with this block rate than if they had a flat rate.

Q Why did you determine that 300 kWh is the appropriate level for the non-summer first block?

A. For Schedule 7 customers, a monthly average of 42.2 percent of energy consumed during summer months is in the first block and, similarly, a monthly average of 40.6 percent of the energy consumed during the non-summer months is under 300 kWh. A first block higher than 300 kWh is not recommended because the average monthly kWh for customers in this schedule is just over 570 kWh. Also, the existing first block in the summer season is currently set at 300 kWh, putting the non-summer block at the same level provides a consistent price signal.

Q. What are the proposed Energy Charges and Service Charge?

A. The Energy Charge for both summer and non-summer first block rates is 6.2725¢ per kWh. The Energy Charge for the summer second block is 9.1267¢ per kWh and the Energy Charge for the non-summer second block is 7.3135¢ per kWh. In addition, the Company is proposing to increase the Service Charge from $6.55 to $10.00 per month for singe-phase service and from $13.10 to $20.00 per month for three-phase service. The rate design proposal for Schedule 7 is included on page 1 of Exhibit No. 1001.

Q. Why did you increase the Service Charge to those levels?

A. The current average Service Charge weighted by single-phase and three-phase current usage blocks is $7.42. Page 2 of Mr. Tatum's Exhibit No. 803 shows the Schedule 7 Service Charge unit cost of $16.54. The proposed Service Charges increase the average rate to $11.33 and move this rate component closer to cost-of-service.

Q. Please describe the proposed changes to the Energy Charges for the first and second blocks.

A. To provide rate stability for lower use customers, the Energy Charges for both first blocks in the summer and non-summer seasons are equal. The Energy Rates for the first blocks were increased by 20.6 percent over current rates. The Energy Rate for the second block for the summer months was increased by 60.3 percent and the second block for the non-summer months was increased by 40.6 percent over current rates. In light of the overall revenue requirement increase of 41.16 percent for Schedule 7, this rate design gives a stronger price signal in the summer than non-summer months and a stronger price signal for usage over 300 kWh per month.

Q. Did you change the Energy Charge differential between the summer and non-summer seasons?

A. Yes. From Mr. Tatum's Exhibit No. 803, the cost-of-service differential between the summer and non-summer $/kWh unit costs is 84 percent. In order to reflect this cost signal, I increased the differential of the average Energy Charge cost between the summer and non-summer from the current 6.3 percent to 17.3 percent.

Q. What is the revenue requirement to be recovered from Small General Service customers taking service under Schedule 7?

A. The annual revenue requirement for Schedule 7 customers as shown on page 4 of Mr. Tatum's Exhibit No. 804 is $1,660,234. This is an annual increase of 41.16 percent.

Q. What is the impact of this proposed rate design on Small General Service customers?

A. Page 1 of Exhibit No. 1002 shows the billing comparison between the Schedule 7 existing rates and proposed rates for typical billing levels. This exhibit shows that with the proposed rate design and with the overall revenue requirement increase of 41.16 percent, no single-phase customer with these typical billing levels will see an annual rate increase over 48 percent.

Q. Are there other changes to the tariff?

A. Yes. In order to align tariff language with current practice, I propose deleting the words "and whose Demand has not exceeded 30 kW more than once during the most recent 12 consecutive billing periods." Not all Schedule 7 customers have demand meters so Idaho Power is unable to screen for this eligibility requirement. Also, the requirement is not in alignment with similar tariffs in other parts of the Idaho Power service territory.

OVERVIEW OF SCHEDULE 9 AND 19 RELATIONSHIPS

Q. How are Schedule 9 and Schedule 19 interrelated and how does it impact rate design?

A. Currently, both Schedule 9 and Schedule 19 provide service at Secondary, Primary, and Transmission Service levels. As customers' loads change, they can transfer between Schedule 9 and Schedule 19 while continuing to take service at the same service level. Both Schedule 9 and Schedule 19 have a summer and non-summer Demand Charge and a Basic Charge. In addition, Schedule 19 has an On-Peak Demand Charge in the summer. The Billing Demand is the average kW supplied during the 15-consecutive-minute period of maximum use during the billing period, adjusted for Power Factor. The On-Peak Billing Demand for Schedule 19 customers is the average kW supplied during the 15-consecutive-minute period of maximum use during the June, July, and August billing periods for the On-Peak time period. The Basic Load Capacity is the average of the two greatest monthly Billing Demands established during the 12-month period which includes and ends with the current billing period.

Q. What is the current relationship between prices on Schedule 9 and Schedule 19?

A. The Service Charge is the same for all service levels for both. The Basic Charge is the same within service levels for both Schedule 9 and Schedule 19. For example, the Basic Charge for Primary Service level is $0.78 per kW per month for both Schedule 9 and Schedule 19, for the Basic Charge for Secondary Service level is $0.38 per kW per month, and the Basic Charge for Transmission level is $.50 for both Schedule 9 and Schedule 19. Likewise, the summer Demand Charge of $4.26 per kW for Schedule 9 Primary Service level is the same as the sum of the summer Demand Charge of $3.90 per kW and the summer On-Peak Demand Charge of $.36 per kW for Schedule 19 Primary Service level. And the Non-summer Demand Charge is $3.86 for Primary Service Levels for both Schedule 9 and Schedule 19. Generally, Secondary and Transmission Service level Demand Charge structures mirror the Primary Service level Demand Charge structures.

Q. Why has this relationship been established?

A. This relationship was established to be reflective of cost and to facilitate customer transitions from Schedule 9 to Schedule 19 and vice versa.

Q. Do your rate design proposals for Schedule 9 and Schedule 19 customers maintain this pricing relationship between schedules?

A. Yes. The rate design proposals for Schedule 9 and Schedule 19 for both Primary Service level and Transmission Service level maintain the relationship between the Service Charge, the Basic Charge, and the Demand Charges on each of the schedules. The relationship between Schedule 9 and Schedule 19 for these two service levels is most important since almost all customer transitions between these two schedules occur within the Primary and Transmission Service levels.

The relationship between Schedule 9 Secondary Service level and Schedule 19 Secondary Service level is much less important. It is much more common for a Schedule 9

Secondary Service level customer to transition to Schedule 9 Primary Service level prior to transferring to Schedule 19.

Q. Does a similar relationship as that between the Service, Demand, and Basic Charges for Schedule 9 and Schedule 19 exist for the Energy Charges on these two schedules?

A. No. The implementation of time-of-use rates for Schedule 19 has made any direct relationship between the Energy Charges more challenging. In general, however, the Energy Charges for Schedule 9 Primary and Transmission Service level have been slightly higher than the corresponding Energy Charges for Schedule 19.

The Energy Charges have been established to achieve the required revenue for the respective customer classes given the values established for the Service, Basic, and Demand Charges.

LARGE GENERAL SERVICE, SCHEDULE 9

Q. What is the present overall rate structure for Schedule 9?

A. Service under Schedule 9 may be taken at Secondary, Primary, or Transmission Service level. This Schedule is applicable to customers whose metered energy usage exceeds 3,000 kWh per billing period for a minimum of three billing periods during the most recent 12 consecutive billing periods or whose Demand has exceeded 30 kW more than once during the most recent 12 consecutive Billing Periods and whose metered demand per billing period has not equaled or exceeded 1,000 kW more than twice during the most recent 12 consecutive billing periods. As of the end of 2008, Idaho Power had 5 customers who take service at Primary Service level, 947 customers who take service at Secondary Service level and no customers taking service at Transmission Service level. All customers taking service under Schedule 9 pay a Service Charge, a Basic Charge, and both summer and non-summer Energy and Demand Charges. Customers taking service under the Secondary level may take service under single-phase or three-phase, whereas

Primary and Transmission customers only take service under three-phase service. Customers taking Primary or Transmission service may also pay a Facilities Charge.

LARGE GENERAL SERVICE, SCHEDULE 9 – SECONDARY

Q. Are you proposing any rate design changes for Schedule 9 Secondary Service level?

A. No. The only modification proposed is that rate component levels will be increased to satisfy the needed revenue requirement.

Q. Please describe the rate proposal for Schedule 9 Secondary Service level.

A. The rate proposal for Schedule 9 Secondary Service level is included on page 2 of Exhibit No. 1001. The cost-of-service unit costs for this schedule are found in Mr. Tatum's Exhibit No. 803, page 3. For Single-Phase service, I am proposing the Service Charge be increased from $8.50 to $11.50 per month. For Three-Phase service, I am proposing the Service Charge be increased from $15.00 to $20.25 per month. This is approximately a 35 percent increase and moves the weighted average of the Service Charge to $13.97, which is closer to the unit cost of $17.42. I am also proposing the Basic Charge be increased from $0.38 to $0.68 per kW, which moves this rate component closer to the unit cost of $3.85 per kW and aligns with other Schedules in the Idaho Power system. The Summer Demand Charge is increased from $3.99 to $5.70 per kW and the Non-summer Demand Charge will stay unchanged at $4.12 per kW. The increase in the Summer Demand component shows movement towards the cost-of-service unit cost of $11.74. The current summer Energy Charge of 3.9776¢ is increased to 4.4290¢ per kWh. The non-summer Energy Charge of 3.6702¢ is increased to 3.8684¢ per kWh.

Q. How did you arrive at these proposed charges?

A. The Service Charge, Basic Charge, and Summer Demand Charge were increased by amounts that showed movement towards cost-of-service while at the same time aligning with both Secondary service offerings in Schedule 19 and with similar schedules across the Idaho Power system. The remainder of the revenue requirement was applied to the Energy Charge components. The summer Energy Charge was increased 11.35 percent while the non-summer Energy Charge was increased 5.4 percent. This provides for an increase of the seasonal rate differential from the current 8 percent to 14 percent, which provides a gradual movement towards the cost-of-service unit cost seasonal differential of 62 percent.

Q. What is the revenue requirement to be recovered from Large General Service customers taking service under Schedule 9 Secondary Service level?

A. The annual revenue requirement for all Schedule 9 Secondary customers, as shown on page 4 of Mr. Tatum's Exhibit No. 804, is $6,951,860, which is a 9.8 percent increase over current rates.

Q. What is the impact of this rate design on Schedule 9 Secondary Service level customers?

A. Pages 2 through 4 of Exhibit No. 1002 show the billing comparison between the Schedule 9 Secondary Service level existing rates and proposed rates for typical billing levels. As can be seen from Exhibit No. 1002, for each Demand level, the higher load factor customers will see a lower overall increase as compared to lower load factor customers. This pricing structure provides an incentive to customers to have higher load factors and thereby being more energy efficient.

<u>LARGE GENERAL SERVICE, SCHEDULE 9 PRIMARY AND TRANSMISSION</u>

Q. What is the present rate structure for Schedule 9 Primary and Transmission Service?

A. All customers taking service under Schedule 9 Primary and Transmission Service Levels pay seasonal Energy Charges, seasonal Demand Charges, a Basic Charge, and a Service Charge. Customers may also pay a Facilities Charge.

Q. Please describe the rate design proposal for Schedule 9 customers receiving service at the Primary and Transmission Service levels.

A. I am proposing that seasonal time-of-use rates be implemented on a mandatory basis for all customers taking service under Schedule 9 at Primary and Transmission Service levels. Under this proposal, the basic time-of-use rate structure for Schedule 9 Primary and Transmission Service levels will be the same as the time-of-use structure currently in place for customers taking service at similar service levels under Schedule 19. This includes On-Peak, Mid-Peak, and Off-Peak Energy Charges that would be in effect during the three summer months from June 1 through August 31. During all other months, Mid-Peak and Off-Peak Energy Charges would be in effect.

In addition to time-of-use Energy Charges, I am also proposing to add a summer On-Peak Demand Charge. This On-Peak Demand charge mirrors the existing On-Peak Demand Charge that is currently in place for Schedule 19 customers. The rate design proposals for Schedule 9 Primary and Transmission Service level are included on pages 3 and 4 of Exhibit No. 1001.

Q. Why are you proposing time-of-use rates for Schedule 9 Primary and Transmission service?

A. Energy is more costly during the summer months and it is more costly during certain hours of the day. Schedule 9 customers currently have the metering in place to accommodate hourly pricing. The implementation of time-of-use rates will provide the economic signal that energy is more costly during both the peak hours of the day and the peak months of the year. Customers can use this pricing information to alter their discretionary usage patterns and thereby lower the overall cost of energy to the Idaho Power system. Customers on time-of-use rates will pay rates that are more closely aligned with the costs they cause. This provides a fair and appropriate rate design; customers whose patterns of energy consumption are less expensive to serve should see that lower cost in their bills.

Q. What is your proposal for the Service Charge and Basic Charge for Schedule 9 Primary and Transmission Service level customers?

A. I am proposing that the Service Charge be increased from $125.00 per month to $215.00 per month. I am proposing that the Basic Charge be increased from $.78 per kW per month of Basic Load Capacity to $1.04 per kW per month.

Q. How did you arrive at these rates?

A. As was discussed earlier, the Service Charge and Basic Charge for both Schedule 9 Primary and Transmission Service levels and Schedule 19 Primary and Transmission Service levels are set to be equal in order to facilitate ease of transition between rate schedules for customers. A more detailed discussion of the Transmission Service level rate proposal is included in the Schedule 19 section. The cost-of-service results show customer unit costs to be $137.94 and $298.52 for Schedule 9 Primary Service and Schedule 19 Primary Service, respectively. These are shown on pages 3 and 4 of Mr. Tatum's Exhibit No. 803. The proposed value of $215.00 for the Service Charge is slightly under the average of the two unit cost values and also aligns with other similar rate schedules across Idaho Power's system. The increase in the Basic Charge moves this rate component closer to cost-of-service results.

Q. Please describe the Company's proposal for Demand Charges for Schedule 9 Primary and Transmission level customers.

A. For Schedule 9 Primary and Transmission customers, the Company is proposing to mirror the rate design currently in place for Schedule 19 customers. During the three summer months, the Company is proposing to implement a two-tiered Demand Charge for monthly peak demand. The proposed summer Demand Charge for Billing Demand, which is the average kW supplied during the 15-minute period of maximum demand during the billing period, is $4.82 per kW for Primary Service and $3.59 for Transmission Service. An additional charge of $0.69 is proposed for each kW of On-Peak Billing Demand, which is the average kW supplied during the 15-minute period of maximum demand during the billing period for the On-Peak hours. For customers whose peak demand during the billing period occurs during the On-Peak period, the Billing Demand and the On-Peak Billing Demand will be the same. However, for customers whose peak demand occurs during the Mid-Peak or Off-Peak period, the Billing Demand will be greater than the On-Peak Billing Demand. During the non-summer months, only Billing Demand will apply. There is no On-Peak Billing Demand during the non-summer months. The proposed Demand Charges for the non-summer months are $4.45 per kW for Primary Service and $3.84 per kW for Transmission Service.

Q. How did you determine the Demand Charges?

A. My overall goal was to move summer and non-summer Demand Charges closer to cost of service while at the same time maintaining relationships among schedules, service levels, and other schedules systemwide.

The summer demand unit costs for Schedule 9 Primary and Schedule 19 Primary are $14.13 and $11.85, respectively, as indicated on pages 3 and 4 of Mr. Tatum's Exhibit No. 803. Current summer demand charges are very low compared to these unit costs and show the need to focus on increasing these rates. I set the total summer demand amount at $5.51 per kW per month, which represents a 29 percent increase over the current rate. This total summer demand amount is separated into two amounts: (1) the On-Peak Demand Charge and (2) the summer Demand Charge.

I set the summer On-Peak Demand Charge at $0.69 per kW per month, which provides alignment with other Oregon schedules, service levels, and other Idaho schedules. The summer Demand Charge for Schedule 9 Primary Service level is $4.82 per kW per month, which is the total summer demand amount of $5.51 less the summer On-Peak

Demand Charge of $0.69. The summer On-Peak Demand Charge is set to the same amount for Schedule 9 Primary and Transmission levels as well as Schedule 19 customers at all service levels. These proposals send a strong demand price signal during the Company's peak time periods.

The non-summer demand unit costs for Schedule 9 Primary and Schedule 19 Primary are $5.36 and $6.07, respectively, as indicated on pages 3 and 4 of Mr. Tatum's Exhibit No. 803. These non-summer demand unit costs are much lower than the summer demand unit cost. I set the non-summer Schedule 9 and Schedule 19 Primary Service level Demand Charge at $4.45 per kW per month, an increase of 15.3 percent over current rates and a movement towards cost-of-service.

The Transmission Service level Summer, Non-summer, and On-Peak Demand Charges were aligned with Schedule 19 Transmission Service level charges in order to reflect similar costs and to maintain traditional relationships.

Q. Is the Company proposing to apply the current Schedule 19 time-of-use block definitions to the new rate design proposal for Schedule 9?

A. Yes.

Q. What are the time-of-use block definitions that the Company is proposing for the Energy Charges?

A. During the three summer months, the Company is proposing three time-of-use blocks. The On-Peak block is defined as 1:00 p.m. to 9:00 p.m. Monday through Friday, except holidays. The Mid-Peak block is defined as 7:00 a.m. to 1:00 p.m. and 9:00 p.m. to 11:00 p.m. Monday through Friday, except holidays, and 7:00 a.m. to 11:00 p.m. Saturday and Sunday, except holidays. The Off-Peak block is defined as 11:00 p.m. to 7:00 a.m. every day Monday through Saturday and all hours on holidays. During the non-summer months, the Company is proposing just two time-of use blocks. The Mid-Peak block during the non-summer months is defined as 7:00 a.m. to 11:00 p.m. Monday through Saturday except holidays. The Off-Peak block is defined as 11:00 p.m. to 7:00 a.m. Monday through Saturday and all hours on Sunday and holidays. All times are in Mountain Time.

Q. What are the specific proposed Energy Charges for Schedule 9 by service level?

A. The Energy Charges for Schedule 9 Primary and Transmission customers by time period for each season are:

Time Period	Service Level: Primary	Service Level: Transmission
Summer		
On-Peak	4.2761¢	4.2042¢
Mid-Peak	3.8874¢	3.8220¢
Off-Peak	3.6331¢	3.5720¢
Non-Summer		
Mid-Peak	3.4094¢	3.3536¢
Off-Peak	3.2470¢	3.1939¢

Q. What were your goals in developing these Energy Charges?

A. The first goal was to calculate new average seasonal Energy Charges that reflect an increase in the summer energy costs. The current differential between the summer and non-summer Energy Charges is 8 percent. I increased these differentials to 17.1 percent, which moves toward the cost-of-service unit cost differential of 66.4 percent as shown in Mr. Tatum's Exhibit 803. My second goal was to apply the time block differentials used in the existing Schedule 19 time-of-use rates to the proposed Schedule 9 Primary and Transmission time-of-use rates. My third goal was to recover the residual revenue requirement given the proposed Service, Basic, and Demand Charges.

Q. Why did you use the current Schedule 19 time-of-use rate differentials for Schedule 9?

A. These differentials, set at approximately 7 percent between the summer Off-Peak and summer Mid-Peak Energy Charges, approximately 10 percent between the summer Mid-Peak and summer On-Peak Energy Charges, and approximately 4 percent between the non-summer Off-Peak and non-summer Mid-Peak Energy Charges, are not very large but do provide an introductory level of time differentiated rates. Customers have the opportunity to become familiar with time variant pricing gradually, see how their usage patterns impact their bills, and plan accordingly.

Q. How did you calculate the specific time-of-use Energy Charges?

A. From the average seasonal Energy Charge calculation explained above, I applied the proposed time-of-use block differentials. The resulting On-Peak, Mid-Peak, and Off-Peak Energy Charges reflect the proposed differentials between rates and also equal the average seasonal energy charge when weighted by usage blocks. These rates give a price signal to customers to reduce their On-Peak usage or to shift their usage from On-Peak to Mid-Peak or Off-Peak time blocks to lower their bill.

From the Primary Service level, the Energy Charges were spread to Schedule 9 Transmission Service level maintaining current rate relationships and maintaining proposed time-of-use differentials.

Q. Why are you proposing that these time-of-use rates for Schedule 9 Primary and Transmission levels be mandatory?

A. These time-of-use rates more accurately reflect the costs to serve the Company's customers and therefore provide a better overall pricing signal and cost recovery mechanism. By providing time-of-use rates to all customers, not just those who might benefit from being on time-of-use rates, we are providing incentives to customers to conserve and/or shift load. If customers respond to this signal by conserving or shifting load, the resulting energy use pattern lowers overall costs for all customers.

Q. How do you propose to implement this new rate design with customers?

A. I propose implementing a customer communication and education plan that provides customers with information on the possible impact of time-of-use rates on their bills. Examples of energy conservation or load shifting ideas will also be provided at that time. By working with customers before the rates go into effect, they can plan and make purchasing decisions and determine how best to react to the new structure. In 2008, Idaho Power implemented a customer communication and education plan for Idaho Schedule 9 customers when time-of-use rates were implemented. The information and process was well received by customers and prepared them for the new rate structure.

Q. What is the revenue requirement to be recovered from Schedule 9 Large General Service customers taking service at the Primary and Transmission levels?

A. The annual revenue requirement for Schedule 9 Primary customers as shown on page 4 of Mr. Tatum's Exhibit No. 804 is $800,098. This represents a 22.19 percent increase over current rates.

Q. What is the billing impact of this rate design proposal on the customers receiving service under Schedule 9 Primary Service level?

A. Page 5 through 7 of Exhibit No. 1002 show the billing comparison between the existing rates and rate structure and proposed rates and rate structure for typical billing levels.

Q. Are you proposing any changes to the Schedule 9 tariff?

A. Yes. There are two changes I propose to the Schedule 9 tariff. First, I propose to take out the language "and whose Demand has exceeded 30 kW more than once during the most recent 12 consecutive billing periods." This is discussed above on page 9. The second change is to permanently change the Power Factor correction level to

90 percent. Idaho Power has been correcting Power Factor to 90 percent since the 2005 date mentioned in the tariff. The added wording is no longer needed.

LARGE POWER SERVICE, SCHEDULE 19

Q. What is the present rate structure for Schedule 19?

A. Service under Schedule 19, just like service under Schedule 9, is provided under Secondary, Primary, and Transmission Service levels. All customers taking service under Schedule 19 pay seasonal time-of-use Energy Charges, seasonal Demand Charges, a summer On-Peak Demand Charge, a Basic Charge, and a Service Charge. Customers taking Primary or Transmission Service may also pay a Facilities Charge. In addition, Schedule 19 includes a 1,000 kW minimum Billing Demand and Basic Load Capacity. As of the end of 2008, Idaho Power had six customers taking service at Primary Service level, two customers taking service at Transmission Service level, and no customers at Secondary Service level.

Q. What is the rate design proposal for Schedule 19?

A. The rate design proposal for Schedule 19 is shown on pages 4 through 6 of Exhibit No. 1001. As explained by Mr. Tatum, a cost-of-service analysis was completed for Schedule 19 Primary customers and Schedule 19 Transmission customers. The cost-of-service analyses are shown on page 4 of Mr. Tatum's Exhibit No. 803.

There are two primary changes to the rate design proposal for Schedule 19 customers. First, the differentials between Off-Peak, Mid-Peak, and On-Peak Energy Charges during the summer season and the differential between Off-Peak and Mid-Peak Energy Charges during non-summer season have been increased. And, second, more emphasis has been placed on the Demand, Basic, and Service Charge components.

Q. Why are you proposing rate changes for Schedule 19 Transmission service level if the cost-of-service results recommend no revenue requirement increase?

A. The overall rate design goals, those of moving toward cost of service and providing energy efficiency signals, should be felt by all customers, whether they receive an increase in revenue requirement or not.

Q. What are the proposed changes for the Service Charge?

A. The proposed Service Charge for Schedule 19 for all service levels is $215.00 per month. The cost-of-service result of the Service Charge for Schedule 19 Primary and Transmission is $298.52 and is shown on page 4 of Mr. Tatum's Exhibit No. 803. The proposed Service Charge of $215.00 represents approximately 72 percent of the cost-of-service results and maintains alignment with Schedule 9 and other systemwide tariffs.

Q. What are the proposed changes for the Basic Charge for Schedule 19?

A. For the Primary Service level, the Basic Charge is $1.04 per kW per month. This amount is approximately 30 percent of the cost-of-service result of $3.48 as shown on page 4 of Mr. Tatum's Exhibit No. 803. This proposal moves the Basic Charge closer to unit cost results and it also aligns the charge with Schedule 19 Primary rates in Idaho.

For the Transmission Service level, the Basic Charge proposal is to lower this charge from $.41 to $.30 per kW per month. The reason this charge is being reduced is to reflect that the cost-of-service result of $0 as shown on page 4 of Mr. Tatum's Exhibit No. 803. The Schedule 9 Transmission Basic Charge aligns with the Schedule 19 Transmission Basic Charge.

The proposed Basic Charges for Schedule 19 Secondary Service is $0.68 per kW per month, this is a 91 percent increase over current rates. The Basic Charge for Secondary Service level was modified to align charges in both Oregon and Idaho Schedule 9 Secondary Service level tariffs. The cost-of-service results for Schedule 9 Secondary rates, as explained previously, are $3.86.

The primary goals that were achieved with these rate design proposals are a movement towards cost-of-service results and an alignment with other schedules and service levels.

Q. Why do you maintain a Basic Charge for Schedule 19 transmission when the cost-of-service results are zero?

A. The purpose of the Basic Charge is to provide a rate mechanism, in addition to the regular Demand Charge, which will more equitably recover the costs associated with the fixed facilities of the peak capacity imposed by the customer. The Basic Charge also provides an incentive for customers to maximize operating efficiency on an annual basis. These are still desirable rate design price signals.

Q. Please describe your proposal for Demand Charges.

A. The proposed summer On-Peak Demand Charge is $0.69 kW for all service levels. The proposed summer Demand Charges are $5.01, $4.82, and $3.59 per kW and the proposed non-summer Demand Charges are $4.12, $4.45, and $3.84 per kW for the Secondary, Primary, and Transmission Service levels, respectively. These Charges were calculated to move towards cost-of-service results for the Primary and Transmission service levels, to emphasize increases in summer demand rates as indicated by cost-of-service results, and to maintain the relationships between schedules and service levels described earlier.

Q. What are the specific proposed Energy Charges by service level for Schedule 19 customers?

A. The Proposed Schedule 19 Energy Charges by service level and time period for each season are:

Time Period		Service Level Secondary	Primary	Transmission
Summer				
	On-Peak	5.4191¢	4.1215¢	3.8928¢
	Mid-Peak	4.1685¢	3.1704¢	2.9941¢
	Off-Peak	3.6248¢	2.7569¢	2.6036¢
Non-Summer				
	Mid-Peak	4.0061¢	2.9668¢	2.7946¢
	Off-Peak	3.5768¢	2.6489¢	2.4952¢

Q. How were these Energy Charges derived?

A. First, new average seasonal Energy Charges were calculated that reflect an increase in the seasonal energy rate differentials. Secondly, larger time-block differentials were applied to these new average seasonal energy charges. And thirdly, the residual revenue requirement was recovered given the proposed Service, Basic, and Demand Charges.

For the Primary Service level, current seasonal Energy Charge differentials are at 7.7 percent. I increased these differentials to 15.2 percent, which moves this value toward the cost-of-service unit cost differential of 61.1 percent as shown in Mr. Tatum's Exhibit No. 803. For the Transmission Service level, current seasonal Energy Charge differentials are at 7.9 percent. I increased these differentials to 15.5 percent, which moves this value toward the cost-of-service unit cost differential of 70.4 percent as shown in Mr. Tatum's Exhibit No. 803. By increasing the seasonal differential, new average seasonal energy charges were derived.

When the new time-of-use Energy Charge differentials were applied to the average seasonal energy charges, the percentage change to Off-Peak Energy Charge was reduced about 2 percent for Primary service level and about 6 percent for Transmission service level charges. These new Off-Peak Energy Charges provide a strong incentive to shift usage to Off-Peak time periods. Mid-Peak and On-Peak Charges were derived in the same manner. Calculating these new Energy Charges was accomplished while at the same time meeting the revenue requirements shown for the Primary and Transmission Service levels as specified by Mr. Tatum's cost-of-service study in Exhibit No. 803.

Q. How did you determine the new seasonal time-of-use Energy Charge differentials?

A. The summer Off-Peak to Mid-Peak differential of 15 percent, summer Mid-Peak to On-Peak differential of 30 percent, and the non-summer Off-Peak to Mid-Peak differential of 12 percent are very similar to those proposed and adopted in Idaho in 2008. These differentials were selected because they provide a price signal that reflects costs on Idaho Power's system.

Q. Do you think these levels are reasonable?

A. Yes. I reviewed time-of-use rate structures of the other utilities and found that a total overall summer differential of 49 percent is within a typical range. The proposed Schedule 19 Primary Service level summer On-Peak Energy Charge of 4.1215¢ cents is well below the average summer marginal cost, which could be viewed as a cap. The proposed differentials align with differentials used for Schedule 19 in Idaho.

Q. Why are you proposing to increase the rate differentials?

A. When time-of-use rates were implemented for Schedule 19 customers four years ago, the differentials between On-Peak, Mid-Peak, and Off-Peak Energy Charges were set at an "introductory" level. By increasing the rate differentials, a stronger price signal is sent that will provide a stronger incentive to conserve or to shift the time of energy usage to a less costly time period. This stronger price signal provides higher benefits to those customers who modify operations or purchase equipment that uses less energy. Overall, this rate structure reflects a better cost recovery mechanism.

Q. What is the revenue requirement to be recovered from Large Power Service customers taking service under Schedule 19?

A. The annual revenue requirement for Schedule 19 Primary Service level customers as shown on page 4 of Mr. Tatum's Exhibit No. 804 is $7,299,613, which represents an 8.75 percent increase. The annual revenue requirement for Schedule 19 Transmission Service level customers as shown on page 4 of Mr. Tatum's Exhibit No. 804 is $3,243,600, indicating a zero percent increase for this service level.

Q. What is the impact of the rate design on Large Power Service customers?

A. Pages 8 through 10 of Exhibit No. 1002 show the billing comparison between existing rates and proposed rates for typical billing levels for Schedule 19 Primary Service level. As can be seen in these pages, customers with higher load factors receive less of an increase than customers with lower load factors. Page 11 through 13 of Exhibit 1002 show the billing comparison between existing rates and proposed rates for typical billing levels for Schedule 19 Transmission Service level. Exhibit No. 1002 shows a small increase in summer rates, a decrease in non-summer rates, and a weighted average monthly change close to zero.

Q. Are there other changes to the tariff?

A. Yes. I am proposing three changes. First, I have added language to the Availability section noting that there are provisions under Rule H providing services impacting this tariff. The language is added for clarity and to align current practice in Oregon with Schedule 19 in Idaho. Second, I have changed Power Factor correction to 90 from 85 as discussed above on page 19. And third, I have clarified the time-of-use time period definition for holidays in order to align with current practice and with other schedules on the system.

Q. Does this conclude your testimony?

A. Yes, it does.

Idaho Power/1001
Witness: Darlene Nemnich

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Darlene Nemnich
Calculation of Revenue Impact – Schedules 7, 9, and 19

July 31, 2009

Idaho Power Company
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Small General Service
Schedule 7

Line No	Description	(1) Usage Blocks	(2) Current Base Rate	(3) Current Base Revenue	(4) Adjusted Base Rate	(5) Adjusted Base Revenue	(6) Proposed Base Rate	(7) Proposed Base Revenue	(8) Revenue Difference	(9) Percent Change
1	Serivce Charge:									
2	Single-Phase	31,195.6	6.55	204,331	6.55	204,331	10.00	311,956	107,625	52.67%
3	Three Phase	4,792.2	13.10	62,778	13.10	62,778	20.00	95,844	33,066	52.67%
4	Total Billings	35,987.8		267,109		267,109		407,800	140,691	52.67%
5	Minimum Charge	63.1	3.00	189	3.00	189	3.00	189	0	0.00%
6	Energy Charge									
	Summer									
7	0-300 kWh	1,411,371	0.044549	62,875	0.052019	73,418	0.062725	88,528	15,110	20.58%
8	Over 300 kWh	2,869,073	0.049449	141,873	0.056919	163,305	0.091267	261,852	98,547	60.35%
9	Summer Energy	4,280,444		204,748		236,723		350,380	113,657	48.01%
10	Non-Summer									
11	0-300 kWh	4,138,896	0.044549	184,384	0.052019	215,301	0.062725	259,612	44,311	20.58%
12	Over 300 kWh	8,781,712	0.044549	391,216	0.052019	456,816	0.073135	642,250	185,434	40.59%
13	Non-Summer Energy	12,920,608		575,600		672,117		901,862	229,745	34.18%
14	Total Energy	17,201,052		780,348		908,840		1,252,242	343,402	37.78%
15	Annual Power Cost Update	17,201,052	0.00747	128,492		0	0	0	0	0.00%
16	Total Revenue			1,176,138		1,176,138		1,660,231	484,093	41.16%

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Large General Service - Secondary
Schedule 9

Line No	Description	(1) Usage Blocks	(2) Current Base Rate	(3) Current Base Revenue	(4) Adjusted Base Rate	(5) Adjusted Base Revenue	(6) Proposed Base Rate	(7) Proposed Base Revenue	(8) Revenue Difference	(9) Percent Change
1	Service Charge:									
2	Single-Phase	11,480.1	8.50	97,581	8.50	97,581	11.50	132,021	34,440	35.29%
3	Three Phase	4,527.5	15.00	67,913	15.00	67,913	20.25	91,682	23,769	35.00%
4	Total Billings	16,007.6		165,494		165,494		223,703	58,209	35.17%
5	Minimum Charge	12.9	5.00	65	5.00	65	5.00	65	0	0.00%
6	Basic Charge (per kW)	530,106	0.38	201,440	0.38	201,440	0.68	360,472	159,032	78.95%
7	Demand Charge									
8	Summer	87,373	4.51	394,050	4.51	394,050	5.70	498,024	103,974	26.39%
9	Non-Summer	290,238	4.12	1,195,782	4.12	1,195,782	4.12	1,195,782	0	0.00%
10	Total Demand	377,611		1,589,832		1,589,832		1,693,806	103,974	6.54%
11	Energy Charge									
12	Summer	26,659,239	0.032306	861,253	0.039776	1,060,398	0.044290	1,180,738	120,340	11.35%
13	Non-Summer	90,297,619	0.029232	2,639,580	0.036702	3,314,103	0.038684	3,493,073	178,970	5.40%
14	Total Energy	116,956,858		3,500,833		4,374,501		4,673,811	299,310	6.84%
15	Annual Power Cost Update	116,956,858	0.007470	873,668		0	0.000000	0	0	0.00%
16	Total Revenue			6,331,332		6,331,332		6,951,857	620,525	9.80%

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Large General Service - Primary
Schedule 9

Line No	Description	(1) Usage Blocks	(2) Current Base Rate	(3) Current Base Revenue	(4) Adjusted Base Rate	(5) Adjusted Base Revenue	(6) Proposed Base Rate	(7) Proposed Base Revenue	(8) Revenue Difference	(9) Percent Change
1	Service Charge	60.0	125.00	7,500	125.00	7,500	215.00	12,900	5,400	72.00%
2	Minimum Charge	2.8	10.00	28	10.00	28	10.00	28	0	0.00%
3	Basic Charge (per kW)	46,987	0.78	36,650	0.78	36,650	1.04	48,866	12,216	33.33%
4	Demand Charge									
5	Summer	9,271	4.26	39,493	4.26	39,493	4.82	44,685	5,192	13.15%
6	Non-Summer	27,854	3.86	107,518	3.86	107,518	4.45	123,952	16,434	15.28%
7	Total Demand	37,125		147,011		147,011		168,637	21,626	14.71%
8	On-Peak Summer	8,965					0.69	6,186	6,186	0.00%
9	Energy Charge									
10	Summer	3,855,826	0.022917	88,364	0.030387	117,167				
11	Non-Summer	12,321,447	0.020646	254,389	0.028116	346,430				
12	Total Energy	16,177,273		342,753		463,597				
13	Proposed Energy Charge									
14	Summer On-peak	1,045,754					0.042761	44,717		
15	Summer Mid-peak	1,696,956					0.038874	65,967		
16	Summer Off-peak	1,113,116					0.036331	40,441		
17	Total Summer	3,855,826						151,125	33,958	28.98%
18	Non-Summer Mid-peak	7,559,140					0.034094	257,721		
19	Non-Summer Off-peak	4,762,307					0.032470	154,632		
20	Total Non-Summer	12,321,447						412,353	65,923	19.03%
21	Total Energy	16,177,273						563,478	99,881	21.54%
22	Annual Power Cost Update	16,177,273	0.007470	120,844		0	0.000000	0	0	0.00%
23	Total Revenue			654,786		654,786		800,095	145,309	22.19%

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Large General Service - Transmission
Schedule 9

Line No	Description	(1) Usage Blocks	(2) Current Base Rate	(3) Current Base Revenue	(4) Adjusted Base Rate	(5) Adjusted Base Revenue	(6) Proposed Base Rate	(7) Proposed Base Revenue	(8) Revenue Difference	(9) Percent Change
1	Service Charge	0.0	125.00	0	125.00	0	215.00	0	0	0.00%
2	Minimum Charge	0.0	10.00	0	10.00	0	10.00	0	0	0.00%
3	Basic Charge (per kW)	0	0.41	0	0.41	0	0.30	0	0	0.00%
4	Demand Charge									
5	Summer	0	4.12	0	4.12	0	3.59	0	0	0.00%
6	Non-Summer	0	3.74	0	3.74	0	3.84	0	0	0.00%
7	Total Demand	0		0		0		0	0	0.00%
8	On-Peak Summer	0					0.69	0	0	0.00%
9	Energy Charge									
10	Summer	0	0.022406	0	0.029876	0				
11	Non-Summer	0	0.020186	0	0.027656	0				
12	Total Energy	0		0		0				
13	Proposed Energy Charge									
14	Summer On-peak	0					0.042042	0		
15	Summer Mid-peak	0					0.038220	0		
16	Summer Off-peak	0					0.035720	0		
17	Total Summer	0						0	0	0.00%
18	Non-Summer Mid-peak	0					0.033536	0		
19	Non-Summer Off-peak	0					0.031939	0		
20	Total Non-Summer	0						0	0	0.00%
21	Total Energy	0						0	0	0.00%
22	Annual Power Cost Update	0	0.007470	0		0	0.000000	0	0	0.00%
23	Total Revenue			0		0		0	0	0.00%

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Large Power Service - Secondary
Schedule 19

Line No	Description	(1) Usage Blocks	(2) Current Base Rate	(3) Current Base Revenue	(4) Adjusted Base Rate	(5) Adjusted Base Revenue	(6) Proposed Base Rate	(7) Proposed Base Revenue	(8) Revenue Difference	(9) Percent Change
1	Service Charge	0.0	$125.00	0	$125.00	0	$215.00	0	0	0.00%
2	Minimum Charge	0.0	$5.00	0	$5.00	0	$10.00	0	0	0.00%
3	Basic Charge (per kW)	0	0.38	0	0.38	0	0.68	0	0	0.00%
4	Demand Charge									
5	Summer	0	4.01	0	4.01	0	5.01	0	0	0.00%
6	Non-Summer	0	3.96	0	3.96	0	4.12	0	0	0.00%
7	Total Demand	0		0		0		0	0	0.00%
8	On-Peak Summer	0	0.36	0	0.36	0	0.69	0	0	0.00%
9	Energy Charge									
10	Summer									
11	On-Peak	0	0.033657	0	0.041127	0	0.054191	0	0	0.00%
12	Mid-Peak	0	0.031978	0	0.039448	0	0.041685	0	0	0.00%
13	Off-Peak	0	0.029805	0	0.037275	0	0.036248	0	0	0.00%
14	Non-Summer									
15	Mid-Peak	0	0.031187	0	0.038657	0	0.040061	0	0	0.00%
16	Off-Peak	0	0.027836	0	0.035306	0	0.035769	0	0	0.00%
17	Total Energy	0		0		0		0	0	0.00%
18	Annual Power Cost Update	0	0.007470	0		0	0.000000	0	0	0.00%
19	Total Revenue			0		0		0	0	0.00%

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Large Power Service - Primary
Schedule 19

Line No	Description	(1) Usage Blocks	(2) Current Base Rate	(3) Current Base Revenue	(4) Adjusted Base Rate	(5) Adjusted Base Revenue	(6) Proposed Base Rate	(7) Proposed Base Revenue	(8) Revenue Difference	(9) Percent Change
1	Service Charge	72.0	$125.00	9,000	$125.00	9,000	$215.00	15,480	6,480	72.00%
2	Minimum Charge	0.0	$10.00	0	$10.00	0	$10.00	0	0	0.00%
3	Basic Charge (per kW)	358,534	0.78	279,656	0.78	279,656	1.04	372,875	93,219	33.33%
4	Demand Charge									
5	Summer	88,078	3.90	343,505	3.90	343,505	4.82	424,537	81,032	23.59%
6	Non-Summer	243,179	3.86	938,671	3.86	938,671	4.45	1,082,147	143,476	15.29%
7	Total Demand	331,257		1,282,176		1,282,176		1,506,684	224,508	17.51%
8	On-Peak Summer kW	85,173	0.36	30,662	0.36	30,662	0.69	58,769	28,107	91.67%
9	Energy Charge									
10	Summer									
11	On-Peak	11,576,370	0.024567	284,397	0.032037	370,872	0.041215	477,120	106,248	28.65%
12	Mid-Peak	20,916,105	0.022175	463,815	0.029645	620,058	0.031704	663,124	43,066	6.95%
13	Off-Peak	15,838,318	0.020667	327,331	0.028137	445,643	0.027569	436,647	(8,996)	-2.02%
14	Non-Summer									
15	Mid-Peak	76,232,903	0.020530	1,565,061	0.028000	2,134,521	0.029668	2,261,678	127,157	5.96%
16	Off-Peak	56,900,309	0.019587	1,114,506	0.027057	1,539,552	0.026489	1,507,232	(32,320)	-2.10%
17	Total Energy	181,464,005		3,755,110		5,110,646		5,345,801	235,155	4.60%
18	Annual Power Cost Update	181,464,005	0.007470	1,355,536		0	0.000000	0	0	0.00%
19	Total Revenue			6,712,140		6,712,140		7,299,609	587,469	8.75%

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Large Power Service - Transmission
Schedule 19

Line No	Description	(1) Usage Blocks	(2) Current Base Rate	(3) Current Base Revenue	(4) Adjusted Base Rate	(5) Adjusted Base Revenue	(6) Proposed Base Rate	(7) Proposed Base Revenue	(8) Revenue Difference	(9) Percent Change
1	Service Charge	25.0	$125.00	3,125	$125.00	3,125	$215.00	5,375	2,250	72.00%
2	Minimum Charge	0.0	$10.00	0	$10.00	0	$10.00	0	0	0.00%
3	Basic Charge (per kW)	365,098	$0.41	149,690	$0.41	149,690	$0.30	109,529	(40,161)	-26.83%
4	Demand Charge									
5	Summer	50,057	$3.52	176,202	$3.52	176,202	$3.59	179,706	3,504	1.99%
6	Non-Summer	125,452	$3.76	471,700	$3.76	471,700	$3.84	481,736	10,036	2.13%
7	Total Demand	175,510		647,902		647,902		661,442	13,540	2.09%
8	On-Peak Summer	48,919	0.36	17,611	0.36	17,611	0.69	33,754	16,143	91.66%
9	Energy Charge									
10	Summer									
11	On-Peak	6,648,339	0.024131	160,431	0.031601	210,094	0.038928	258,807	48,713	23.19%
12	Mid-Peak	11,673,631	0.021780	254,252	0.029250	341,454	0.029941	349,520	8,066	2.36%
13	Off-Peak	9,659,601	0.020300	196,090	0.027770	268,247	0.026036	251,497	(16,750)	-6.24%
14	Non-Summer									
15	Mid-Peak	32,811,301	0.020092	659,245	0.027562	904,345	0.027946	916,945	12,600	1.39%
16	Off-Peak	26,319,742	0.019169	504,523	0.026639	701,132	0.024952	656,730	(44,402)	-6.33%
17	Total Energy	87,112,615		1,774,541		2,425,272		2,433,499	8,227	0.34%
18	Annual Power Cost Update	87,112,615	0.007470	650,731		0	0.000000	0	0	0.00%
19	Total Revenue			3,243,600		3,243,600		3,243,599	(1)	0.00%

Idaho Power/1002
Witness: Darlene Nemnich

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Darlene Nemnich
Typical Monthly Billing Comparisons – Schedules 7, 9, and 19

July 31, 2009

Idaho Power Company
Typical Monthly Billing Comparison
State of Oregon
General Rate Case
Filed July 31, 2009

Small General Service - Single-Phase
Schedule 7

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		Summer			Non-Summer			Avg Mth Cost -12 Mths		
Line No	Energy kWh	Current Revenue	Proposed Revenue	Percent Difference	Current Revenue	Proposed Revenue	Percent Difference	Current Revenue	Proposed Revenue	Percent Difference
1	100	11.75	16.27	38.47%	11.75	16.27	38.47%	11.75	16.27	38.47%
2	200	16.95	22.55	33.04%	16.95	22.55	33.04%	16.95	22.55	33.04%
3	300	22.16	28.82	30.05%	22.16	28.82	30.05%	22.16	28.82	30.05%
4	400	29.32	46.51	58.63%	27.36	39.25	43.46%	27.85	41.07	47.47%
5	500	35.01	55.63	58.90%	32.56	46.57	43.03%	33.17	48.84	47.24%
6	600	40.70	64.76	59.12%	37.76	53.88	42.69%	38.50	56.60	47.01%
7	700	46.39	73.89	59.28%	42.96	61.19	42.43%	43.82	64.37	46.90%
8	800	52.09	83.01	59.36%	48.17	68.51	42.23%	49.15	72.14	46.78%
9	900	57.78	92.14	59.47%	53.37	75.82	42.06%	54.47	79.90	46.69%
10	1,000	63.47	101.27	59.56%	58.57	83.14	41.95%	59.80	87.67	46.61%
11	1,100	69.16	110.39	59.62%	63.77	90.45	41.84%	65.12	95.44	46.56%
12	1,200	74.85	119.52	59.68%	68.97	97.76	41.74%	70.44	103.20	46.51%
13	1,300	80.54	128.65	59.73%	74.17	105.08	41.67%	75.76	110.97	46.48%
14	1,400	86.24	137.77	59.75%	79.38	112.39	41.58%	81.10	118.74	46.41%
15	1,500	91.93	146.90	59.80%	84.58	119.70	41.52%	86.42	126.50	46.38%
16	2,000	120.39	192.53	59.92%	110.59	156.27	41.31%	113.04	165.34	46.27%
17	2,500	148.85	238.17	60.01%	136.60	192.84	41.17%	139.66	204.17	46.19%
18	3,000	177.31	283.80	60.06%	162.61	229.41	41.08%	166.29	243.01	46.14%
19	4,000	234.23	375.07	60.13%	214.63	302.54	40.96%	219.53	320.67	46.07%
20	5,000	291.15	466.34	60.17%	266.65	375.68	40.89%	272.78	398.35	46.03%

Idaho Power Company
Calculation of Proposed Rates
State of Oregon
General Rate Case
Filed July 31, 2009

Schedule 9 Secondary Service
Typical Monthly Billing Comparison - Single Phase
Summer

Line No	Demand kW	BLC kW	Load Factor	Energy kWh	(1) Curr Rate	(2) Proposed Rate	(3) Difference (2) - (1)	(4) Percent Difference
1	10	11	20%	1,440	115.06	139.76	24.70	21.47%
2			35%	2,520	158.02	187.59	29.58	18.72%
3			50%	3,600	200.97	235.42	34.45	17.14%
4			65%	4,680	243.93	283.26	39.33	16.12%
5			80%	5,760	286.89	331.09	44.20	15.41%
6	50	57	20%	7,200	542.05	654.15	112.10	20.68%
7			35%	12,600	756.84	893.31	136.48	18.03%
8			50%	18,000	971.63	1,132.48	160.85	16.55%
9			65%	23,400	1,186.42	1,371.65	185.23	15.61%
10			80%	28,800	1,401.21	1,610.81	209.60	14.96%
11	100	114	20%	14,400	1,075.59	1,296.80	221.20	20.57%
12			35%	25,200	1,505.18	1,775.13	269.95	17.93%
13			50%	36,000	1,934.76	2,253.46	318.70	16.47%
14			65%	46,800	2,364.34	2,731.79	367.46	15.54%
15			80%	57,600	2,793.92	3,210.12	416.21	14.90%
16	300	342	20%	43,200	3,209.78	3,867.39	657.60	20.49%
17			35%	75,600	4,498.53	5,302.38	803.86	17.87%
18			50%	108,000	5,787.27	6,737.38	950.11	16.42%
19			65%	140,400	7,076.01	8,172.38	1,096.37	15.49%
20			80%	172,800	8,364.75	9,607.37	1,242.62	14.86%
21	500	570	20%	72,000	5,343.97	6,437.98	1,094.01	20.47%
22			35%	126,000	7,491.88	8,829.64	1,337.76	17.86%
23			50%	180,000	9,639.78	11,221.30	1,581.52	16.41%
24			65%	234,000	11,787.68	13,612.96	1,825.28	15.48%
25			80%	288,000	13,935.59	16,004.62	2,069.03	14.85%
26	750	855	20%	108,000	8,011.71	9,651.22	1,639.51	20.46%
27			35%	189,000	11,233.56	13,238.71	2,005.15	17.85%
28			50%	270,000	14,455.42	16,826.20	2,370.78	16.40%
29			65%	351,000	17,677.28	20,413.69	2,736.41	15.48%
30			80%	432,000	20,899.13	24,001.18	3,102.05	14.84%

Idaho Power Company
Calculation of Proposed Rates
State of Oregon
General Rate Case
Filed July 31, 2009

Schedule 9 Secondary Service
Typical Monthly Billing Comparison - Single Phase
Non-Summer

Line No	Demand kW	BLC kW	Load Factor	Energy kWh	(1) Current Rate	(2) Proposed Rate	(3) Difference 2-1	(4) Percent Difference
1	10	11	20%	1,440	106.73	115.88	9.15	8.58%
2			35%	2,520	146.37	157.66	11.29	7.72%
3			50%	3,600	186.01	199.44	13.44	7.22%
4			65%	4,680	225.65	241.22	15.58	6.90%
5			80%	5,760	265.28	283.00	17.72	6.68%
6	50	57	20%	7,200	500.41	534.78	34.37	6.87%
7			35%	12,600	698.61	743.68	45.07	6.45%
8			50%	18,000	896.80	952.57	55.78	6.22%
9			65%	23,400	1,094.99	1,161.47	66.48	6.07%
10			80%	28,800	1,293.18	1,370.36	77.18	5.97%
11	100	114	20%	14,400	992.33	1,058.07	65.74	6.62%
12			35%	25,200	1,388.71	1,475.86	87.15	6.28%
13			50%	36,000	1,785.09	1,893.64	108.55	6.08%
14			65%	46,800	2,181.47	2,311.43	129.96	5.96%
15			80%	57,600	2,577.86	2,729.22	151.36	5.87%
16	300	342	20%	43,200	2,959.99	3,151.21	191.22	6.46%
17			35%	75,600	4,149.13	4,404.57	255.44	6.16%
18			50%	108,000	5,338.28	5,657.93	319.66	5.99%
19			65%	140,400	6,527.42	6,911.29	383.87	5.88%
20			80%	172,800	7,716.57	8,164.66	448.09	5.81%
21	500	570	20%	72,000	4,927.64	5,244.35	316.70	6.43%
22			35%	126,000	6,909.55	7,333.28	423.73	6.13%
23			50%	180,000	8,891.46	9,422.22	530.76	5.97%
24			65%	234,000	10,873.37	11,511.16	637.79	5.87%
25			80%	288,000	12,855.28	13,600.09	744.82	5.79%
26	750	855	20%	108,000	7,387.22	7,860.77	473.56	6.41%
27			35%	189,000	10,360.08	10,994.18	634.10	6.12%
28			50%	270,000	13,332.94	14,127.58	794.64	5.96%
29			65%	351,000	16,305.80	17,260.98	955.18	5.86%
30			80%	432,000	19,278.66	20,394.39	1,115.72	5.79%

Idaho Power Company
Calculation of Proposed Rates
State of Oregon
General Rate Case
Filed July 31, 2009

Schedule 9 Secondary Service
Typical Monthly Billing Comparison - Single Phase
Weighted Average Monthly

Line No	Demand kW	BLC kW	Load Factor	Energy kWh	(1) Curr Rate	(2) Proposed Rate	(3) Difference (2) - (1)	(4) Percent Difference
1	10	11	20%	1,440	108.81	121.85	13.04	11.98%
2			35%	2,520	149.28	165.15	15.86	10.63%
3			50%	3,600	189.75	208.44	18.69	9.85%
4			65%	4,680	230.22	251.73	21.51	9.34%
5			80%	5,760	270.69	295.02	24.34	8.99%
6	50	57	20%	7,200	510.82	564.63	53.80	10.53%
7			35%	12,600	713.16	781.09	67.92	9.52%
8			50%	18,000	915.50	997.55	82.05	8.96%
9			65%	23,400	1,117.84	1,214.01	96.17	8.60%
10			80%	28,800	1,320.19	1,430.47	110.29	8.35%
11	100	114	20%	14,400	1,013.15	1,117.75	104.61	10.32%
12			35%	25,200	1,417.83	1,550.67	132.85	9.37%
13			50%	36,000	1,822.51	1,983.60	161.09	8.84%
14			65%	46,800	2,227.19	2,416.52	189.33	8.50%
15			80%	57,600	2,631.87	2,849.44	217.57	8.27%
16	300	342	20%	43,200	3,022.44	3,330.25	307.82	10.18%
17			35%	75,600	4,236.48	4,629.02	392.54	9.27%
18			50%	108,000	5,450.52	5,927.79	477.27	8.76%
19			65%	140,400	6,664.57	7,226.56	562.00	8.43%
20			80%	172,800	7,878.61	8,525.33	646.72	8.21%
21	500	570	20%	72,000	5,031.73	5,542.76	511.03	10.16%
22			35%	126,000	7,055.13	7,707.37	652.24	9.24%
23			50%	180,000	9,078.54	9,871.99	793.45	8.74%
24			65%	234,000	11,101.95	12,036.61	934.66	8.42%
25			80%	288,000	13,125.35	14,201.22	1,075.87	8.20%
26	750	855	20%	108,000	7,543.34	8,308.38	765.05	10.14%
27			35%	189,000	10,578.45	11,555.31	976.86	9.23%
28			50%	270,000	13,613.56	14,802.24	1,188.68	8.73%
29			65%	351,000	16,648.67	18,049.16	1,400.49	8.41%
30			80%	432,000	19,683.78	21,296.09	1,612.31	8.19%

Idaho Power Company
Calculation of Proposed Rates
State of Oregon
General Rate Case
Filed July 31, 2009

Schedule 9 Primary
Typical Monthly Billing Comparison
Summer

Line No	Demand kW	On-Peak Demand kW	BLC kW	Load Factor	Energy kWh	(1) Curr Rate	(2) Proposed Rate	(3) Difference (2) - (1)	(4) Percent Difference
1	500	484	633	20%	72,000	4,936.45	6,438.69	1,502.24	30.43%
2				35%	126,000	6,577.35	8,555.16	1,977.82	30.07%
3				50%	180,000	8,218.24	10,671.64	2,453.39	29.85%
4				65%	234,000	9,859.14	12,788.11	2,928.97	29.71%
5				80%	288,000	11,500.04	14,904.58	3,404.54	29.60%
6	600	580	759	20%	86,400	5,898.74	7,683.43	1,784.69	30.26%
7				35%	151,200	7,867.82	10,223.20	2,355.38	29.94%
8				50%	216,000	9,836.89	12,762.96	2,926.07	29.75%
9				65%	280,800	11,805.97	15,302.73	3,496.76	29.62%
10				80%	345,600	13,775.05	17,842.50	4,067.45	29.53%
11	750	725	949	20%	108,000	7,342.17	9,550.54	2,208.36	30.08%
12				35%	189,000	9,803.52	12,725.25	2,921.73	29.80%
13				50%	270,000	12,264.87	15,899.95	3,635.09	29.64%
14				65%	351,000	14,726.21	19,074.66	4,348.45	29.53%
15				80%	432,000	17,187.56	22,249.37	5,061.81	29.45%
16	800	774	1,012	20%	115,200	7,823.32	10,172.91	2,349.59	30.03%
17				35%	201,600	10,448.75	13,559.26	3,110.51	29.77%
18				50%	288,000	13,074.19	16,945.62	3,871.43	29.61%
19				65%	374,400	15,699.63	20,331.97	4,632.35	29.51%
20				80%	460,800	18,325.06	23,718.33	5,393.27	29.43%
21	900	870	1,139	20%	129,600	8,785.61	11,417.64	2,632.04	29.96%
22				35%	226,800	11,739.22	15,227.29	3,488.07	29.71%
23				50%	324,000	14,692.84	19,036.95	4,344.11	29.57%
24				65%	421,200	17,646.46	22,846.60	5,200.14	29.47%
25				80%	518,400	20,600.07	26,656.25	6,056.18	29.40%
26	975	943	1,234	20%	140,400	9,507.32	12,351.20	2,843.87	29.91%
27				35%	245,700	12,707.07	16,478.32	3,771.24	29.68%
28				50%	351,000	15,906.83	20,605.44	4,698.61	29.54%
29				65%	456,300	19,106.58	24,732.56	5,625.99	29.45%
30				80%	561,600	22,306.33	28,859.68	6,553.36	29.38%

Idaho Power Company
Calculation of Proposed Rates
State of Oregon
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Filed July 31, 2009

Schedule 9 Primary
Typical Monthly Billing Comparison
Non-Summer

Line No	Demand kW	BLC kW	Load Factor	Energy kWh	(1) Current Rate	(2) Proposed Rate	(3) Difference 2-1	(4) Percent Difference
1	500	633	20%	72,000	4,572.94	5,507.68	934.75	20.44%
2			35%	126,000	6,091.20	7,314.86	1,223.66	20.09%
3			50%	180,000	7,609.46	9,122.04	1,512.58	19.88%
4			65%	234,000	9,127.73	10,929.22	1,801.49	19.74%
5			80%	288,000	10,645.99	12,736.40	2,090.41	19.64%
6	600	759	20%	86,400	5,462.52	6,566.22	1,103.70	20.20%
7			35%	151,200	7,284.44	8,734.84	1,450.40	19.91%
8			50%	216,000	9,106.36	10,903.45	1,797.09	19.73%
9			65%	280,800	10,928.27	13,072.07	2,143.79	19.62%
10			80%	345,600	12,750.19	15,240.68	2,490.49	19.53%
11	750	949	20%	108,000	6,796.90	8,154.03	1,357.12	19.97%
12			35%	189,000	9,074.30	10,864.79	1,790.49	19.73%
13			50%	270,000	11,351.70	13,575.56	2,223.87	19.59%
14			65%	351,000	13,629.09	16,286.33	2,657.24	19.50%
15			80%	432,000	15,906.49	18,997.10	3,090.61	19.43%
16	800	1,012	20%	115,200	7,241.70	8,683.29	1,441.60	19.91%
17			35%	201,600	9,670.92	11,574.78	1,903.86	19.69%
18			50%	288,000	12,100.14	14,466.27	2,366.13	19.55%
19			65%	374,400	14,529.36	17,357.75	2,828.39	19.47%
20			80%	460,800	16,958.59	20,249.24	3,290.65	19.40%
21	900	1,139	20%	129,600	8,131.28	9,741.83	1,610.55	19.81%
22			35%	226,800	10,864.16	12,994.75	2,130.59	19.61%
23			50%	324,000	13,597.04	16,247.68	2,650.64	19.49%
24			65%	421,200	16,329.91	19,500.60	3,170.69	19.42%
25			80%	518,400	19,062.79	22,753.52	3,690.74	19.36%
26	975	1,234	20%	140,400	8,798.48	10,535.73	1,737.26	19.74%
27			35%	245,700	11,759.09	14,059.73	2,300.64	19.56%
28			50%	351,000	14,719.70	17,583.73	2,864.03	19.46%
29			65%	456,300	17,680.32	21,107.73	3,427.41	19.39%
30			80%	561,600	20,640.93	24,631.73	3,990.80	19.33%

Idaho Power Company
Calculation of Proposed Rates
State of Oregon
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Filed July 31, 2009

Schedule 9 Primary
Typical Monthly Billing Comparison
Weighted Average Monthly

Line No	Demand kW	BLC kW	Load Factor	Energy kWh	(1) Curr Rate	(2) Proposed Rate	(3) Difference (2) - (1)	(4) Percent Difference
1	500	633	20%	72,000	4,663.81	5,740.44	1,076.62	23.08%
2			35%	126,000	6,212.74	7,624.94	1,412.20	22.73%
3			50%	180,000	7,761.66	9,509.44	1,747.78	22.52%
4			65%	234,000	9,310.58	11,393.94	2,083.36	22.38%
5			80%	288,000	10,859.50	13,278.45	2,418.94	22.27%
6	600	759	20%	86,400	5,571.58	6,845.52	1,273.95	22.87%
7			35%	151,200	7,430.28	9,106.93	1,676.64	22.56%
8			50%	216,000	9,288.99	11,368.33	2,079.34	22.38%
9			65%	280,800	11,147.70	13,629.73	2,482.03	22.26%
10			80%	345,600	13,006.40	15,891.13	2,884.73	22.18%
11	750	949	20%	108,000	6,933.22	8,503.15	1,569.93	22.64%
12			35%	189,000	9,256.60	11,329.91	2,073.30	22.40%
13			50%	270,000	11,579.99	14,156.66	2,576.67	22.25%
14			65%	351,000	13,903.37	16,983.41	3,080.04	22.15%
15			80%	432,000	16,226.76	19,810.17	3,583.41	22.08%
16	800	1,012	20%	115,200	7,387.10	9,055.70	1,668.59	22.59%
17			35%	201,600	9,865.38	12,070.90	2,205.52	22.36%
18			50%	288,000	12,343.65	15,086.11	2,742.45	22.22%
19			65%	374,400	14,821.93	18,101.31	3,279.38	22.13%
20			80%	460,800	17,300.21	21,116.51	3,816.31	22.06%
21	900	1,139	20%	129,600	8,294.87	10,160.78	1,865.92	22.49%
22			35%	226,800	11,082.93	13,552.89	2,469.96	22.29%
23			50%	324,000	13,870.99	16,944.99	3,074.01	22.16%
24			65%	421,200	16,659.05	20,337.10	3,678.05	22.08%
25			80%	518,400	19,447.11	23,729.20	4,282.10	22.02%
26	975	1,234	20%	140,400	8,975.69	10,989.60	2,013.91	22.44%
27			35%	245,700	11,996.09	14,664.38	2,668.29	22.24%
28			50%	351,000	15,016.49	18,339.16	3,322.67	22.13%
29			65%	456,300	18,036.88	22,013.94	3,977.06	22.05%
30			80%	561,600	21,057.28	25,688.72	4,631.44	21.99%

Idaho Power Company
Calculation of Proposed Rates
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Filed July 31, 2009

Schedule 19 Primary
Typical Monthly Billing Comparison
Summer

Line No	Demand kW	On-Peak Demand kW	BLC kW	Load Factor	Energy kWh	(1) Curr Rate	(2) Proposed Rate	(3) Difference (2) - (1)	(4) Percent Difference
1	1,000	967	1,160	50%	360,000	15,982.16	18,654.37	2,672.21	16.72%
2				60%	432,000	18,123.01	21,003.51	2,880.51	15.89%
3				70%	504,000	20,263.86	23,352.66	3,088.81	15.24%
4				80%	576,000	22,404.70	25,701.81	3,297.10	14.72%
5				90%	648,000	24,545.55	28,050.96	3,505.40	14.28%
6	2,500	2,418	2,900	50%	900,000	39,767.90	46,313.42	6,545.52	16.46%
7				60%	1,080,000	45,120.02	52,186.28	7,066.26	15.66%
8				70%	1,260,000	50,472.14	58,059.15	7,587.01	15.03%
9				80%	1,440,000	55,824.26	63,932.02	8,107.76	14.52%
10				90%	1,620,000	61,176.38	69,804.89	8,628.51	14.10%
11	4,000	3,868	4,640	50%	1,440,000	63,553.64	73,972.47	10,418.83	16.39%
12				60%	1,728,000	72,117.03	83,369.06	11,252.02	15.60%
13				70%	2,016,000	80,680.42	92,765.64	12,085.22	14.98%
14				80%	2,304,000	89,243.82	102,162.23	12,918.42	14.48%
15				90%	2,592,000	97,807.21	111,558.82	13,751.61	14.06%
16	5,500	5,319	6,380	50%	1,980,000	87,339.38	101,631.52	14,292.14	16.36%
17				60%	2,376,000	99,114.04	114,551.83	15,437.78	15.58%
18				70%	2,772,000	110,888.71	127,472.14	16,583.43	14.96%
19				80%	3,168,000	122,663.37	140,392.45	17,729.07	14.45%
20				90%	3,564,000	134,438.04	153,312.76	18,874.72	14.04%
21	7,000	6,769	8,120	50%	2,520,000	111,125.12	129,290.57	18,165.45	16.35%
22				60%	3,024,000	126,111.06	145,734.60	19,623.54	15.56%
23				70%	3,528,000	141,096.99	162,178.63	21,081.64	14.94%
24				80%	4,032,000	156,082.93	178,622.66	22,539.73	14.44%
25				90%	4,536,000	171,068.86	195,066.69	23,997.83	14.03%
26	8,500	8,220	9,860	50%	3,060,000	134,910.86	156,949.62	22,038.76	16.34%
27				60%	3,672,000	153,108.07	176,917.37	23,809.30	15.55%
28				70%	4,284,000	171,305.28	196,885.12	25,579.84	14.93%
29				80%	4,896,000	189,502.48	216,852.87	27,350.39	14.43%
30				90%	5,508,000	207,699.69	236,820.62	29,120.93	14.02%

Idaho Power Company
Calculation of Proposed Rates
State of Oregon
General Rate Case
Filed July 31, 2009

Schedule 19 Primary
Typical Monthly Billing Comparison
Non-Summer

Line No	Demand kW	BLC kW	Load Factor	Energy kWh	(1) Current Rate	(2) Proposed Rate	(3) Difference 2-1	(4) Percent Difference
1	1,000	1,160	50%	360,000	14,824.72	16,062.75	1,238.03	8.35%
2			60%	432,000	16,811.70	18,101.02	1,289.32	7.67%
3			70%	504,000	18,798.69	20,139.29	1,340.61	7.13%
4			80%	576,000	20,785.67	22,177.57	1,391.89	6.70%
5			90%	648,000	22,772.66	24,215.84	1,443.18	6.34%
6	2,500	2,900	50%	900,000	36,874.30	39,834.38	2,960.08	8.03%
7			60%	1,080,000	41,841.76	44,930.06	3,088.30	7.38%
8			70%	1,260,000	46,809.22	50,025.74	3,216.52	6.87%
9			80%	1,440,000	51,776.68	55,121.41	3,344.73	6.46%
10			90%	1,620,000	56,744.14	60,217.09	3,472.95	6.12%
11	4,000	4,640	50%	1,440,000	58,923.88	63,606.01	4,682.13	7.95%
12			60%	1,728,000	66,871.82	71,759.10	4,887.28	7.31%
13			70%	2,016,000	74,819.75	79,912.18	5,092.43	6.81%
14			80%	2,304,000	82,767.69	88,065.26	5,297.57	6.40%
15			90%	2,592,000	90,715.62	96,218.34	5,502.72	6.07%
16	5,500	6,380	50%	1,980,000	80,973.46	87,377.64	6,404.18	7.91%
17			60%	2,376,000	91,901.87	98,588.13	6,686.26	7.28%
18			70%	2,772,000	102,830.28	109,798.62	6,968.34	6.78%
19			80%	3,168,000	113,758.70	121,009.11	7,250.41	6.37%
20			90%	3,564,000	124,687.11	132,219.60	7,532.49	6.04%
21	7,000	8,120	50%	2,520,000	103,023.04	111,149.27	8,126.23	7.89%
22			60%	3,024,000	116,931.93	125,417.17	8,485.24	7.26%
23			70%	3,528,000	130,840.82	139,685.06	8,844.25	6.76%
24			80%	4,032,000	144,749.70	153,952.96	9,203.25	6.36%
25			90%	4,536,000	158,658.59	168,220.85	9,562.26	6.03%
26	8,500	9,860	50%	3,060,000	125,072.62	134,920.90	9,848.28	7.87%
27			60%	3,672,000	141,961.98	152,246.20	10,284.22	7.24%
28			70%	4,284,000	158,851.35	169,571.50	10,720.16	6.75%
29			80%	4,896,000	175,740.71	186,896.80	11,156.09	6.35%
30			90%	5,508,000	192,630.08	204,222.11	11,592.03	6.02%

Idaho Power Company
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Schedule 19 Primary
Typical Monthly Billing Comparison
Weighted Average Monthly

Line No	Demand kW	BLC kW	Load Factor	Energy kWh	(1) Curr Rate	(2) Proposed Rate	(3) Difference (2) - (1)	(4) Percent Difference
1	1,000	1,160	50%	360,000	15,114.08	16,710.66	1,596.58	10.56%
2			60%	432,000	17,139.53	18,826.65	1,687.12	9.84%
3			70%	504,000	19,164.98	20,942.64	1,777.66	9.28%
4			80%	576,000	21,190.43	23,058.63	1,868.20	8.82%
5			90%	648,000	23,215.88	25,174.62	1,958.74	8.44%
6	2,500	2,900	50%	900,000	37,597.70	41,454.14	3,856.44	10.26%
7			60%	1,080,000	42,661.33	46,744.12	4,082.79	9.57%
8			70%	1,260,000	47,724.95	52,034.09	4,309.14	9.03%
9			80%	1,440,000	52,788.58	57,324.07	4,535.49	8.59%
10			90%	1,620,000	57,852.20	62,614.04	4,761.84	8.23%
11	4,000	4,640	50%	1,440,000	60,081.32	66,197.63	6,116.31	10.18%
12			60%	1,728,000	68,183.12	74,661.59	6,478.47	9.50%
13			70%	2,016,000	76,284.92	83,125.54	6,840.62	8.97%
14			80%	2,304,000	84,386.72	91,589.50	7,202.78	8.54%
15			90%	2,592,000	92,488.52	100,053.46	7,564.94	8.18%
16	5,500	6,380	50%	1,980,000	82,564.94	90,941.11	8,376.17	10.14%
17			60%	2,376,000	93,704.92	102,579.06	8,874.14	9.47%
18			70%	2,772,000	104,844.89	114,217.00	9,372.11	8.94%
19			80%	3,168,000	115,984.87	125,854.94	9,870.08	8.51%
20			90%	3,564,000	127,124.84	137,492.89	10,368.05	8.16%
21	7,000	8,120	50%	2,520,000	105,048.56	115,684.60	10,636.04	10.12%
22			60%	3,024,000	119,226.71	130,496.52	11,269.81	9.45%
23			70%	3,528,000	133,404.86	145,308.45	11,903.59	8.92%
24			80%	4,032,000	147,583.01	160,120.38	12,537.37	8.50%
25			90%	4,536,000	161,761.16	174,932.31	13,171.15	8.14%
26	8,500	9,860	50%	3,060,000	127,532.18	140,428.08	12,895.90	10.11%
27			60%	3,672,000	144,748.51	158,413.99	13,665.49	9.44%
28			70%	4,284,000	161,964.83	176,399.91	14,435.08	8.91%
29			80%	4,896,000	179,181.16	194,385.82	15,204.67	8.49%
30			90%	5,508,000	196,397.48	212,371.74	15,974.26	8.13%

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Schedule 19 Transmission
Typical Monthly Billing Comparison
Summer

Line No	Demand kW	On-Peak Demand kW	BLC kW	Load Factor	Energy kWh	(1) Curr Rate	(2) Proposed Rate	(3) Difference (2) - (1)	(4) Percent Difference
1	1,000	977	1,600	50%	360,000	15,199.88	16,021.29	821.41	5.40%
2				60%	432,000	17,309.32	18,233.72	924.41	5.34%
3				70%	504,000	19,418.75	20,446.16	1,027.41	5.29%
4				80%	576,000	21,528.18	22,658.59	1,130.41	5.25%
5				90%	648,000	23,637.61	24,871.02	1,233.41	5.22%
6	2,500	2,443	4,000	50%	900,000	37,812.21	39,730.73	1,918.52	5.07%
7				60%	1,080,000	43,085.79	45,261.81	2,176.02	5.05%
8				70%	1,260,000	48,359.37	50,792.89	2,433.52	5.03%
9				80%	1,440,000	53,632.95	56,323.97	2,691.02	5.02%
10				90%	1,620,000	58,906.54	61,855.05	2,948.51	5.01%
11	4,000	3,908	6,400	50%	1,440,000	60,424.53	63,440.16	3,015.63	4.99%
12				60%	1,728,000	68,862.26	72,289.89	3,427.63	4.98%
13				70%	2,016,000	77,299.99	81,139.62	3,839.63	4.97%
14				80%	2,304,000	85,737.73	89,989.35	4,251.62	4.96%
15				90%	2,592,000	94,175.46	98,839.08	4,663.62	4.95%
16	5,500	5,374	8,800	50%	1,980,000	83,036.86	87,149.60	4,112.74	4.95%
17				60%	2,376,000	94,638.74	99,317.98	4,679.24	4.94%
18				70%	2,772,000	106,240.62	111,486.35	5,245.74	4.94%
19				80%	3,168,000	117,842.50	123,654.73	5,812.23	4.93%
20				90%	3,564,000	129,444.38	135,823.11	6,378.73	4.93%
21	7,000	6,839	11,200	50%	2,520,000	105,649.18	110,859.04	5,209.85	4.93%
22				60%	3,024,000	120,415.21	126,346.06	5,930.85	4.93%
23				70%	3,528,000	135,181.24	141,833.09	6,651.85	4.92%
24				80%	4,032,000	149,947.27	157,320.11	7,372.84	4.92%
25				90%	4,536,000	164,713.30	172,807.14	8,093.84	4.91%
26	8,500	8,305	13,600	50%	3,060,000	128,261.51	134,568.47	6,306.96	4.92%
27				60%	3,672,000	146,191.69	153,374.15	7,182.46	4.91%
28				70%	4,284,000	164,121.86	172,179.82	8,057.96	4.91%
29				80%	4,896,000	182,052.04	190,985.49	8,933.45	4.91%
30				90%	5,508,000	199,982.22	209,791.17	9,808.95	4.90%

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Schedule 19 Transmission
Typical Monthly Billing Comparison
Non-Summer

Line No	Demand kW	BLC kW	Load Factor	Energy kWh	(1) Current Rate	(2) Proposed Rate	(3) Difference 2-1	(4) Percent Difference
1	1,000	1,600	50%	360,000	14,315.42	14,115.81	(199.62)	-1.39%
2			60%	432,000	16,270.31	16,031.97	(238.34)	-1.46%
3			70%	504,000	18,225.19	17,948.13	(277.06)	-1.52%
4			80%	576,000	20,180.07	19,864.29	(315.79)	-1.56%
5			90%	648,000	22,134.96	21,780.45	(354.51)	-1.60%
6	2,500	4,000	50%	900,000	35,601.05	34,967.01	(634.04)	-1.78%
7			60%	1,080,000	40,488.26	39,757.42	(730.85)	-1.81%
8			70%	1,260,000	45,375.47	44,547.82	(827.66)	-1.82%
9			80%	1,440,000	50,262.68	49,338.22	(924.46)	-1.84%
10			90%	1,620,000	55,149.90	54,128.62	(1,021.27)	-1.85%
11	4,000	6,400	50%	1,440,000	56,886.68	55,818.22	(1,068.46)	-1.88%
12			60%	1,728,000	64,706.22	63,482.86	(1,223.36)	-1.89%
13			70%	2,016,000	72,525.76	71,147.51	(1,378.25)	-1.90%
14			80%	2,304,000	80,345.30	78,812.15	(1,533.14)	-1.91%
15			90%	2,592,000	88,164.83	86,476.80	(1,688.04)	-1.91%
16	5,500	8,800	50%	1,980,000	78,172.32	76,669.43	(1,502.89)	-1.92%
17			60%	2,376,000	88,924.18	87,208.31	(1,715.87)	-1.93%
18			70%	2,772,000	99,676.04	97,747.20	(1,928.84)	-1.94%
19			80%	3,168,000	110,427.91	108,286.09	(2,141.82)	-1.94%
20			90%	3,564,000	121,179.77	118,824.97	(2,354.80)	-1.94%
21	7,000	11,200	50%	2,520,000	99,457.95	97,520.64	(1,937.31)	-1.95%
22			60%	3,024,000	113,142.14	110,933.76	(2,208.37)	-1.95%
23			70%	3,528,000	126,826.33	124,346.89	(2,479.44)	-1.95%
24			80%	4,032,000	140,510.52	137,760.02	(2,750.50)	-1.96%
25			90%	4,536,000	154,194.71	151,173.14	(3,021.56)	-1.96%
26	8,500	13,600	50%	3,060,000	120,743.58	118,371.84	(2,371.74)	-1.96%
27			60%	3,672,000	137,360.10	134,659.21	(2,700.88)	-1.97%
28			70%	4,284,000	153,976.61	150,946.58	(3,030.03)	-1.97%
29			80%	4,896,000	170,593.13	167,233.95	(3,359.18)	-1.97%
30			90%	5,508,000	187,209.64	183,521.32	(3,688.33)	-1.97%

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Schedule 19 Transmission
Typical Monthly Billing Comparison
Weighted Average Monthly

Line No	Demand kW	On-Peak Demand kW	BLC kW	Load Factor	Energy kWh	(1) Curr Rate	(2) Proposed Rate	(3) Difference (2) - (1)	(4) Percent Difference
1	1,000	977	1,600	50%	360,000	14,536.54	14,592.18	55.64	0.38%
2				60%	432,000	16,530.06	16,582.41	52.35	0.32%
3				70%	504,000	18,523.58	18,572.63	49.05	0.26%
4				80%	576,000	20,517.10	20,562.86	45.76	0.22%
5				90%	648,000	22,510.62	22,553.09	42.47	0.19%
6	2,500	2,443	4,000	50%	900,000	36,153.84	36,157.94	4.10	0.01%
7				60%	1,080,000	41,137.65	41,133.51	(4.13)	-0.01%
8				70%	1,260,000	46,121.45	46,109.09	(12.36)	-0.03%
9				80%	1,440,000	51,105.25	51,084.66	(20.59)	-0.04%
10				90%	1,620,000	56,089.06	56,060.23	(28.83)	-0.05%
11	4,000	3,908	6,400	50%	1,440,000	57,771.15	57,723.71	(47.44)	-0.08%
12				60%	1,728,000	65,745.23	65,684.62	(60.61)	-0.09%
13				70%	2,016,000	73,719.32	73,645.54	(73.78)	-0.10%
14				80%	2,304,000	81,693.40	81,606.45	(86.95)	-0.11%
15				90%	2,592,000	89,667.49	89,567.37	(100.12)	-0.11%
16	5,500	5,374	8,800	50%	1,980,000	79,388.45	79,289.47	(98.98)	-0.12%
17				60%	2,376,000	90,352.82	90,235.73	(117.09)	-0.13%
18				70%	2,772,000	101,317.19	101,181.99	(135.20)	-0.13%
19				80%	3,168,000	112,281.55	112,128.25	(153.31)	-0.14%
20				90%	3,564,000	123,245.92	123,074.50	(171.42)	-0.14%
21	7,000	6,839	11,200	50%	2,520,000	101,005.76	100,855.24	(150.52)	-0.15%
22				60%	3,024,000	114,960.41	114,786.84	(173.57)	-0.15%
23				70%	3,528,000	128,915.06	128,718.44	(196.62)	-0.15%
24				80%	4,032,000	142,869.71	142,650.04	(219.66)	-0.15%
25				90%	4,536,000	156,824.35	156,581.64	(242.71)	-0.15%
26	8,500	8,305	13,600	50%	3,060,000	122,623.06	122,421.00	(202.06)	-0.16%
27				60%	3,672,000	139,567.99	139,337.95	(230.05)	-0.16%
28				70%	4,284,000	156,512.93	156,254.89	(258.03)	-0.16%
29				80%	4,896,000	173,457.86	173,171.84	(286.02)	-0.16%
30				90%	5,508,000	190,402.79	190,088.78	(314.01)	-0.16%

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE __________

IN THE MATTER OF THE APPLICATION	)
OF IDAHO POWER COMPANY FOR	)
AUTHORITY TO INCREASE ITS RATES	)
AND CHARGES FOR ELECTRIC	)
SERVICE IN THE STATE OF OREGON.	)
	)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

SCOTT D. SPARKS

July 31, 2009

Q. Please state your name and business address.

A. My name is Scott D. Sparks 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 "Company") as a Senior Pricing Analyst in the Pricing and Regulatory Services Department.

Q. Please describe your educational background.

A. In May of 1989, I received a Bachelor of Business Administration degree in Business Management from Boise State University.

Q. Please describe your work experience with Idaho Power.

A. I started my employment with Idaho Power in 1985 as a part-time mail clerk and have held positions as Meter Reader, Customer Service Representative, Economic Analyst, Human Resource/Compensation Analyst, Pricing and Regulatory Services Analyst, and Resource Planning Analyst.

In January of 1991, after two years in the Customer Service Department, I was offered and I accepted a position in the Company's Energy Services Department. My responsibilities over six years in the department varied from conservation program evaluation, special studies, and load forecasting and research. In 1995, I was asked to temporarily transfer to the Human Resources Department to assist with implementation of the Company's reorganization, benefit, and compensation plans.

In 1998, I applied for and accepted a position in the Pricing and Regulatory Services Department where I was responsible for reviving the Company's resource planning and integrated resource planning processes. As part of reorganization, in 2001, I was reassigned to the Power Supply Planning Department where I acted as the lead analyst for the Integrated Resource Plan. In July 2003, I left the Company to pursue self-employment in the real estate and construction sectors. I returned to the Company as a Senior Pricing Analyst in the Pricing and Regulatory Services Department in June 2008.

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

A. My testimony addresses proposed changes to the Company's Oregon Schedule 24, Agricultural Irrigation Service, as well as all Oregon lighting and non-metered retail tariff schedules, Schedules 15, 40, 41, and 42.

Q. Have you prepared or supervised the preparation of certain exhibits relating to your rate design testimony?

A. Yes, I have prepared or supervised the preparation of the following exhibits relating to rate design:

Exhibit	**Description**
Exhibit Nos. 1101-1106	Calculation of Revenue Impact Schedules 15, 24, 40, 41, and 42
Exhibit No. 1107	Typical Monthly Billing Comparisons Schedule 24, Secondary, Agricultural Irrigation Service

RATE DESIGN

Q. What were the Company's overall objectives in arriving at the proposed rate designs for the service schedules identified in your testimony?

A. As discussed in Company witness Michael Youngblood's testimony, the first objective was to establish prices that primarily reflect the costs of the services provided. Mr. Youngblood's testimony also discusses a second objective of presenting cost-based rate proposals designed to encourage energy efficiency. Finally, the proposed designs were developed keeping in mind the Company's objective of providing consistency and continuity throughout the Company's service territory.

SCHEDULE 24 - AGRICULTURAL IRRIGATION SERVICE

Q. What is the current rate structure for Schedule 24?

A. Service under Schedule 24 is classified as being either “in-season” or “out-of-season.” The in-season period for each customer begins with the customer’s meter reading for the May billing period and ends with the customer’s meter reading for the September billing period. The out-of-season period encompasses all other billing periods.

Schedule 24 customers pay both an Energy Charge and a Demand Charge for metered usage during the in-season and out-of-season periods. Although the Energy Charge is the same during the in-season and out-of-season periods, the Demand Charge varies from $4.55 per kilowatt during the in-season billing periods to $0.80 per kilowatt during the out-of-season billing periods.

In addition to the monthly energy and demand charges, customers pay a monthly Service Charge of $12.00 during the in-season and a reduced Service Charge of $3.00 during the out-of-season as a means to encourage customers to continue service throughout the out-of-season period.

Both Secondary Service and Transmission Service levels are available under Schedule 24. Currently, no customers are taking Transmission Service.

Q. Please describe the rate design proposal for Schedule 24.

A. Consistent with the overall objectives mentioned previously, the Company proposes to move individual rate components closer to the cost-of-service as indicated in Company witness Timothy Tatum’s Marginal Cost Analysis (page 5 of Exhibit No. 803). The rate design proposal shown in Exhibit No. 1102 also targets the proposed cap of 44.69 percent average revenue increase as indicated on page 4 of Mr. Tatum’s Exhibit No. 804.

In addition, the Company is proposing to move all in-season energy sales to a load-factor pricing mechanism. Out-of-season energy sales will not be impacted by the proposed load-factor energy rate design.

Q. Please explain what is meant by “load factor.”

A. A load factor is the ratio of the kilowatt-hours ("kWhs") supplied during a designated period to the peak or maximum load in kilowatts ("kW") occurring in that same period. It is computed by dividing the number of the monthly billed kilowatt-hours by the product of the billed kW and the number of hours in the billing month. To attain efficiency goals, it is beneficial to maximize the kWh usage for each kW of billed demand. The higher the load factor, the higher the energy efficiency.

Q. Can you provide examples of how load factors are calculated?

A. Yes. If a customer has 1 kW of billed demand and utilizes 720 kWhs of energy in a typical 30-day month, the resulting load factor is 100 percent, 720 kWhs / 720 (1 kW x 24 hours x 30 days). If another customer has the same 1 kW billed demand but only uses 360 kWhs during the 30-day month, the customer would have a 50 percent (360/720) load factor.

Q. Why is a customer's load factor meaningful or important?

A. A customer's load factor is a measure of how fully electric facilities are being utilized. For example, assume one customer has facilities required to provide service to a 100-horsepower pump that is utilized only 30 percent of the time. A second customer has a 50-horsepower pump that is utilized 60 percent of the time. Even though each customer may have the same kilowatt-hours energy charges over a month's time, the demand charges for the smaller pump will be proportionally less. In turn, the smaller pump will have a load factor sufficient to benefit from reduced energy rates. This variance in consumption can be termed "right-sizing equipment."

Right-sized equipment helps to minimize the Company's peak demand if the device is being utilized during the Company's highest demand periods.

Q. Why would an energy rate design that is conditional on a customer's load factor be preferable to a uniform energy rate?

A. Currently, a uniform energy rate is applied to all in-season energy sales. Efficiency is neither rewarded nor discouraged by such an energy pricing mechanism. Unrecognized efficiencies of the higher load-factor customers result in the subsidization of the lesser efficient lower load-factor customers. Implementation of the proposed load-factor pricing mechanism will lessen the cross-subsidization between these two types of customers.

Q. How is the load-factor pricing rate mechanism structured?

A. Instead of applying a single uniform energy rate to all in-season energy sales, the load-factor pricing mechanism divides the energy sales into two groups: (1) energy rate for all kWhs up to a certain load-factor threshold and (2) energy rate for all kWhs above that level.

Q. What is the typical load factor of the Company's Oregon Irrigation customers?

A. Using the median in-season load factors for each of the past three years (2006, 2007, and 2008), the average in-season load factor for Oregon Irrigation customers was 39.4 percent. The three-year average median out-of-season load factor was 3.9 percent.

Q. For the proposed load-factor pricing rate structure, what load factor served as the benchmark for determining the kWh tiers in the rate design?

A. The proposed rate design targets bill neutrality for customers attaining the median load factor of 39.4 percent (284 kWhs per kW) in an in-season month. Those with a monthly load factor greater than that level will benefit from lower bill charges than if all kWhs are charged a single, uniform energy rate. Conversely, customers with a load factor below 39.4 percent in an in-season month will experience increased bill charges compared to a single uniform energy rate. Again, load-factor pricing is not being recommended for out-of-season kWh usage.

Q. In order to accomplish the expressed goal of revenue neutrality at 284 kWhs, how large is the first tier of the proposed energy rate design?

A. The first energy tier in the energy rate design is for the first 164 kWhs per kW. The second tier is for all additional kWhs per kW. These are the same tier levels approved and currently in place in the Company's Idaho jurisdiction.

Q. How was the 164 kWhs per kW load-factor threshold derived in Idaho?

A. The 164 kWhs per kW threshold was derived from the estimated 2007 median load-factor of all Idaho Irrigation customers. Here, the median load-factor was determined to be 45.6 percent or 328 kWhs per kW. The load-factor threshold was then set at 164 kWhs per kW (328 kWhs per kW / 2) to achieve revenue neutrality.

Q. How large is the proposed price differential between the first energy rate tier (first 164 kWhs per kW) and the second tier (all other kWhs per kW)?

A. The Company is proposing a 3 percent price differential between the two energy tiers. This small differential will minimize any sizable economic impacts of the proposed rate design while customers are becoming more knowledgeable about the pricing structure. This differential is the same as that in Idaho and will help avoid any rate structure confusion for irrigators operating in both the Idaho and Oregon jurisdictions.

Q. Does a load-factor energy pricing rate design interfere with, or become counter-productive to, the goals of either the Company's Irrigation Efficiency Rewards Program or the Irrigation Peak Rewards Program?

A. No. Participants in the Irrigation Efficiency Rewards Program receive rewards to improve the energy efficiency of their existing irrigation systems or their installation choices for new systems. The right-sizing of equipment encouraged by this Program should enhance the customer's load factor. Therefore, load-factor energy pricing has the potential to provide a second set of benefits to the participants in the Irrigation Efficiency Rewards Program.

The Irrigation Peak Rewards Program provides economic credits to customers who allow the Company to turn off specific irrigation equipment on a regular, pre-scheduled basis. Compared to the Irrigation Efficiency Rewards Program, energy efficiency goals are not as directly related to this Company program. However, whenever participating customers maintain a monthly in-season load factor above the 39.4 percent threshold, they will also receive a second additional benefit of lower energy bills resulting from load-factor energy pricing. Because participants in the program generally shift their usage to another time period, load-factor energy pricing should not make any significant changes to their monthly load factor. As a result, participation levels in the program should not be negatively affected by the proposed load-factor pricing rate design.

Q. What goals are addressed with the introduction of load-factor energy pricing for in-season usage?

A. As previously mentioned, the Company seeks to establish prices that reflect the costs of the services provided and establish rate designs that encourage the wise and efficient use of energy. Load-factor energy pricing supports both of these goals because it encourages customers to "right-size" their irrigation equipment by lowering kW demand and spreading their hours of operation over longer periods of time; thus increasing their load factor and efficiency.

Q. Will all irrigation customers be able to immediately make adjustments that will allow them to benefit from load-factor energy pricing?

A. Most likely not. Right-sizing irrigation equipment and modifying operations would probably occur gradually over time. However, load-factor energy pricing will encourage efficient choices when equipment and operational decisions are being made.

Q. Are you proposing any other rate design changes to Schedule 24?

A. Yes, I am proposing to eliminate the current out-of-season Demand Charge of $0.80 per kilowatt and adjust the out-of-season Energy Charge to facilitate the Company's collection of these costs.

Q. Why are you proposing to eliminate the out-of-season Demand Charge?

A. The absence of an out-of-season Demand Charge was initially designed to accommodate customers who need to use energy during the out-of-season period for minor purposes, such as testing pumps, performing maintenance, or repositioning pivots. The low energy consumption associated with these activities was billed at the out-of-season Energy Charge but did not include a charge for demand presumably because the low usage generally occurred during the time of the year when capacity costs are lowest, i.e., fall and spring. With the implementation of an out-of-season Demand Charge, customers are currently charged for the peak demand when they test their pumps or move their pivot irrigation systems. Consequently, the Demand Charge is disproportionately high compared to the amount of energy used, which has caused discontentment for irrigation customers needing to perform the minor activities described above.

Furthermore, by not charging an out-of-season Demand Charge, the Company can maintain continuity between its Idaho and Oregon irrigation schedules and alleviate customer misunderstandings through consistent administration of Schedule 24 provisions.

Q. When was the current out-of-season Demand Charge for Schedule 24 irrigation customers implemented?

A. The out-of-season Demand Charge for Oregon Schedule 24 was implemented in the Company's last general rate case in 2004, Order No. 05-871 Docket No. UE 167.

Q. Please describe your proposal to align the individual rate components for Schedule 24 with the cost-of-service study.

A. The Unit Cost results detailed on page 5 of Mr. Tatum's Exhibit No. 803 indicate that the current Service Charge, Demand Charge, and Energy Charge rate components are not in alignment with costs. The proposed rates move the Service Charge and Demand Charge individual rate components closer to the costs indicated by the cost-of-service study.

Q. What approach was used in determining the amount of increase for each rate component?

A. The Company first considered the percentage increase of the overall revenue requirement identified for Schedule 24, Secondary Service, resulting from the Cost-of Service Study (Mr. Tatum's Exhibit No. 804, page 4). This percentage (44.69 percent) established the combined target for all rate components. Second, the in-season Service Charge was set to approximately 75 percent of cost-of-service based on the Cost-of-Service Index for Schedule 24 (Mr. Tatum's Exhibit No. 804, page 4). Third, the in-season tiered rates were established achieving a 3 percent differential based on the flat energy rate. The flat rate was calculated by taking the existing energy rate (0.035845¢) and adding the required revenue percent increase of 44.69 percent, Exhibit No. 1102. Fourth, the out-of-season energy charge was set to a flat rate by multiplying the overall revenue requirement percentage increase by current base rates and adding the foregone revenue resulting from the elimination of the out-of-season demand charge. Finally, the in-season demand charge was increased to more closely align with the cost-of-service study and to recover the Company's required revenue for Schedule 24, Secondary Service.

Q. How were the rates for Transmission Service determined?

A. Once the component rates for Secondary Service were determined, the charges for Transmission Service were established to maintain the current relationship between service levels. No Irrigation customers are currently taking Transmission Service within the Company's Oregon jurisdiction.

Q. What is the revenue requirement to be recovered from Schedule 24?

A. The total annual revenue to be recovered from customers taking service under Schedule 24 is $4,118,203. This is shown on page 4 of Mr. Tatum's Exhibit No. 804.

Q. What is the proposed Service Charge for Schedule 24?

A. The proposed Service Charge for Secondary Service during the in-season period increases from $12.00 to $15.00 per month. The proposed Service Charge for Transmission Service during the in-season is $128 per month. For both Secondary and Transmission Service, the Service Charge during the out-of-season remains at $3.00 per month.

Q. What is the proposed Demand Charge for Schedule 24?

A. The proposed in-season Demand Charge for Secondary Service increases from $4.55 to $7.20 per kW per month. The proposed in-season Demand Charge for Transmission Service increases from $4.30 to $6.80 per kW per month. For reasons previously mentioned, the Company proposes to bill the Demand Charge to Schedule 24 customers during the in-season period only.

Q. What are the proposed Energy Charges for Schedule 24?

A. The proposed in-season Energy Charges for Secondary Service increase from 3.5845¢ per kWh to 5.2513¢ per kWh for the first 164 kWhs per kW, and from 3.5845¢ per kWh to 5.0977¢ per kW for all other energy usage. The proposed out-of-season Energy Charges increase from 3.5845¢ per kWh to 5.5152¢ per kWh.

The proposed in-season Energy Charges for Transmission Service increase from 3.4439¢ per kWh to 5.0453¢ per kWh for the first 164 kWhs per kW, and from 3.4439¢ per kWh to 4.8977¢ per kWh for all other energy usage. The proposed out-of-season Energy Charges increase from 3.4439¢ per kWh to 5.2989¢ per kWh.

Q. What is the impact of the new rate design on Schedule 24 Secondary Service customers?

A. It is difficult to determine the absolute impact on Schedule 24 Secondary Service customers because usage varies each year based on weather, market prices for crops, and crop rotations. However, when examining 2008 actual irrigation usage in Oregon, approximately 53 percent of the customers taking service under Schedule 24 would receive an increase in their annual bills of less than 44.69 percent, the total overall capped percentage increase proposed for the class as a whole.

Q. How does the new rate design affect customer bills at different levels of consumption and varying load-factors?

A. Exhibit No. 1107 shows the impacts on customers' bills as load-factors increase at different levels of demand. The "In-Season" table demonstrates that with the proposed in-season load-factor energy pricing mechanism, the higher a customer's load-factor the more beneficial the rate structure tends to be in terms of the impact to customer bills, i.e., the percentage increase in billing amounts is smaller when comparing the current rate to the proposed rate. In contrast, customers with the highest percentage increase in in-season billing amounts have the lowest average load factors.

The "Out-of-Season" table in Exhibit No. 1107 shows essentially the opposite billing impact of the load-factor pricing mechanism utilized in the "In-Season" table. With a flat energy rate, as load-factors go up and energy consumption increases, the percentage differences in customer bills also increase. Here, irrigation customer customers can benefit by reducing their hours of operation and conserving energy consumption.

<u>LIGHTING & NON-METERED SCHEDULES</u>

Q. What are the Company's lighting and non-metered service schedules?

A. The Company's lighting and non-metered schedules are Dusk-to-Dawn Customer Lighting, Schedule 15; Unmetered General Service , Schedule 40; Street Lighting Service, Schedule 41; and Traffic Control Signal Lighting Service, Schedule 42.

SCHEDULE 15 – Dusk to Dawn Customer Lighting

Q. What is the present rate structure for Dusk-to-Dawn Customer Lighting on Schedule 15?

A. Customers taking service under Schedule 15 are charged on a per lamp basis. Lamps currently served under Schedule 15 include 100, 200, and 400 watt high pressure sodium vapor area lighting, 200 and 400 watt high pressure sodium vapor flood lighting, and 400 and 1,000 watt metal halide flood lighting.

Q. Are you proposing any changes to the rate design for Schedule 15?

A. No rate design changes are being proposed.

Q. Are you proposing any administrative changes to Schedule 15?

A. No, I am not.

Q. What is the revenue requirement for customers taking service under Schedule 15?

A. As shown on page 4 of Mr. Tatum's Exhibit No. 804, the revenue requirement for Schedule 15 is $98,625.

Q. Please describe the proposed base rates for Schedule 15.

A. Since additional revenue is not required from Schedule 15 customers, no changes are proposed to existing base rates other than increases resulting from the Annual Power Cost Adjustment as described in Mr. Youngblood's testimony. All existing base rates increase by the Annual Power Cost Adjustment only.

SCHEDULE 40 – Unmetered General Service

Q. What is the present rate structure for Unmetered General Service under Schedule 40?

A. Customers taking service under Schedule 40 are unmetered and have energy loads and periods of operation which are fixed. The customer's computed usage is charged a flat Energy Charge. Demand- and customer-related costs are also recovered through the Energy Charge. The minimum bill for service under Schedule 40 is $1.50 per month.

Q. Are you proposing any changes to the rate design for Schedule 40?

A. No rate design changes are being proposed.

Q. Are any changes being proposed to Schedule 40?

A. Yes. The Company proposes to implement a $1.00 Intermittent Usage Charge applicable only to municipalities or agencies of federal, state, or county governments with an authorized Point of Delivery having the potential of intermittent variations in energy usage. This additional charge was recently approved and implemented in the Company's Idaho jurisdiction.

Q. What is the intent of the Intermittent Usage Charge?

A. It has come to the Company's attention that various unmetered service connections under Schedule 40 have customer-provided equipment installed that provides the opportunity for minimal amounts of variable or intermittent power usage. The Intermittent Usage Charge is intended to recover the cost of customer-provided equipment installed that provides the opportunity for minimal amounts of variable or intermittent power usage.

Q. Please provide an example and explain the rationale for the proposed Intermittent Usage Charge.

A. Within the Company's Idaho jurisdiction, the Idaho Department of Transportation ("ITD") currently has a number of traffic counters, weather stations, and similar equipment that receive service under the Company's Schedule 40. The nameplate rating of the equipment as well as the hours utilized are used to compute the amount of energy to be billed. However, installations of power strips (outlets) are also integral to the configuration of the devices and intermittent and minimal power usages for drills, soldering irons, etc., are required for incidental maintenance and repairs. Since these devices provide a potential for variable usage, they are not currently in strict compliance with the eligibility standards of Schedule 40.

Strict compliance with the current schedule would require that each site be metered. Installation and maintenance of metering equipment, monthly meter readings, etc., would be a very expensive undertaking and achieve little. In fact, the Company recently worked with ITD to install sample meters at specific locations in an attempt to determine the level of variable power usage. In the end, these installations had such minimal usage that the registered usage at the time of the reading did not even indicate 1 kWh of usage during the billing period.

In order to accommodate the customers' and Company's needs and to maintain compliance with the Company's tariff, it was agreed that charging a $1.00 Intermittent Usage Charge per month in lieu of installing meters is a fair and reasonable solution to bring these service locations into compliance with Schedule 40. The Company wishes to offer this optional charge to municipalities or agencies of federal, state, or county governments in Oregon.

Q. What is the revenue requirement to be recovered from customers taking service under Schedule 40?

A. As shown on page 4 of Mr. Tatum's Exhibit No. 804, the annual revenue requirement for Schedule 40 is $958.

Q. Please describe the proposed base rate for Schedule 40.

A. The proposed base rate for Schedule 40 is included in Exhibit No. 1104. It targets the proposed class revenue increase of 24.11 percent as shown on page 4 of Mr. Tatum's Exhibit No. 804. The Energy Charge remains flat and increases from 5.9880¢ per kWh to 7.4297¢ per kWh.

SCHEDULE 41 – Street Lighting Service

Q. What is the present rate structure for Street Lighting Service, Schedule 41?

A. Charges for Street Lighting Service are based on a per-lamp (including ballast) or per-pole basis. Street Lighting is divided into two types: (1) Company-Owned and (2) Customer-Owned. Both metered and non-metered service is provided for Company-Owned lighting and Customer-Owned lighting.

Q. Are you proposing any changes to the rate design for Schedule 41?

A. No rate design changes are being proposed.

Q. Are you proposing any other changes to Schedule 41?

A. Yes. Four changes are being proposed to Schedule 41.

First, the Company is proposing to delete all language referring to "Exhibit A" under the Service Location and Period section. "Exhibit A" was a handwritten document used in the past before the Company's billing system was automated. The Company now provides this information electronically upon request.

Second, in acknowledgement of the fact that meter service is not provided for Company-owned overhead lighting systems and never has been provided, the Company is proposing to remove Metered Service lamp charges under the Monthly Charges section of "A" – Overhead Lighting, Company-owned System.

Third, clarification of the Accelerated Replacement of Existing Services section for Company-Owned systems is being proposed. In order to exercise the accelerated replacement option, the Customer must make payments prior to the work being performed. Because prepayment is required, it is inconsistent to base the charges on "actual labor, time, and mileage costs." Therefore the proposed tariff text has been modified to state the charges will be based on the Company's "designed cost estimate" which includes labor, time, and mileage.

Fourth, under section B, "Customer-Owned System," I am proposing to add definitions for Energy and Maintenance Service and Energy-Only Service. Both of these services are currently offered under the existing schedule; however, inclusion of these definitions will clarify the service offerings and eligibility for each service. More description headings have also been added to the Monthly Charges for each type of service.

Q. What is the annual revenue requirement to be recovered from customers taking service under Schedule 41?

A. As shown on page 4 of Mr. Tatum's Exhibit No. 804, the annual revenue requirement for Schedule 41 customers is $120,312.

Q. Please describe the proposed base rates for Schedule 41.

A. The proposed base rates for Schedule 41 are included in Exhibit No. 1105. Each per-lamp charge for both non-metered and metered service increases by the overall 12.46 percent increase proposed on page 4 of Mr. Tatum's Exhibit No. 804. In addition, the per-kWh charge for metered service also increases by 12.46 percent from 4.0000¢ to 4.4984¢. The monthly meter charge of $8.00 remains unchanged. At this time there are no customers receiving metered street lighting service in Oregon.

<u>SCHEDULE 42 – Traffic Control Signal Lighting Service</u>

Q. What is the present rate structure for Traffic Control Signal Lighting Service, Schedule 42?

A. Customers taking service under Schedule 42 pay a flat Energy Charge for each kWh of estimated energy use for non-metered systems and for each kWh of actual usage for metered systems. For non-metered systems, usage is estimated based on the number and size of lamps burning simultaneously in each signal and the average number of hours per day the signal is operated. There is no minimum charge under Schedule 42.

Q. Are you proposing any changes to the rate design for Schedule 42?

A. No rate design changes are being proposed.

Q. What is the revenue requirement to be recovered from customers taking service under Schedule 42?

A. As shown on page 4 of Mr. Tatum's Exhibit No. 804, the annual revenue requirement for Schedule 42 is $1,283.

Q. Please describe the proposed base rate for Schedule 42.

A. The proposed base rate for Schedule 42 is included in Exhibit No. 1106. It targets the proposed capped class revenue increase of 61.55 percent shown on page 4 of Mr. Tatum's Exhibit No. 804. The Energy Charge increases from 4.5970¢ per kWh to 7.4265 per kWh.

Q. Is the Company proposing any other changes to Schedule 42?

A. No it is not.

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

A. Yes, it does.

Idaho Power/1101
Witness: Scott D. Sparks

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Scott D. Sparks
Calculation of Revenue Impact − Schedule 15

July 31, 2009

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
General Rate Case
Filed July 31, 2009

Dusk to Dawn Customer Lighting
Schedule 15

Line No	Description	(1) Use	(2) Lamps	(3) Current Base Rate	(4) Current Base Revenue	(5) Adjusted Base Rate	(6) Adjusted Base Revenue	(7) Proposed Base Rate	(8) Proposed Base Revenue	(9) Revenue Difference	(10) Percent Change
1	Area Lighting:										
2	High Pressure Sodium Vapor:										
3	100 Watt	303,341	7,777	$9.27	72,093	$9.62	74,815	$9.62	74,815	(1)	0.00%
4	200 Watt	52,648	712	$15.03	10,701	$15.38	10,951	$15.38	10,951	(0)	0.00%
5	400 Watt	26,701	171	$24.02	4,107	$24.37	4,167	$24.37	4,167	(0)	0.00%
6	Flood Lighting:										
7	High Pressure Sodium Vapor:										
8	200 Watt	17,945	241	$18.31	4,413	$18.66	4,497	$18.66	4,497	0	0.00%
9	400 Watt	23,449	148	$27.32	4,043	$27.67	4,095	$27.67	4,095	(0)	0.00%
10	Metal Halide:										
11	400 Watt	0	0	$30.58	0	$30.93	0	$30.93	0	0	0.00%
12	1000 Watt	0	0	$55.87	0	$56.22	0	$56.22	0	0	0.00%
13	Total	424,083	9,049		95,358		98,526		98,525	(1)	0.00%
14	Minimum Charge		33.2	$3.00	100	$3.00	100	$3.00	100	0	0.00%
15	Annual Power Cost Update	424,083	0.0	0.007470	3,168		0	0.000000	0	0	0.00%
16	Total Revenue	424,083			98,626		98,626		98,625	(1)	0.00%

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Scott D. Sparks
Calculation of Revenue Impact − Schedule 24 (Secondary)

July 31, 2009

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
General Rate Case
Filed July 31, 2009

Agricultural Irrigation Service - Secondary
Schedule 24

Line No	Description	(1) Usage Blocks	(2) Current Base Rate	(3) Current Base Revenue	(4) Adjusted Base Rate	(5) Adjusted Base Revenue	(6) Proposed Base Rate	(7) Proposed Base Revenue	(8) Revenue Difference	(9) Percent Change
1	Service Charge									
2	In-Season	6,440.8	$12.00	77,290	$12.00	77,290	$15.00	96,612	19,322	25.00%
3	Out-Season	11,788.0	$3.00	35,364	$3.00	35,364	$3.00	35,364	0	0.00%
4	Total	18,228.8		112,654		112,654		131,976	19,322	17.15%
5	Minimum Charge	129.8	$3.00	389	$3.00	389	$3.00	389	0	0.00%
6	Demand Charge									
7	In-Season	111,758	$4.55	508,498	$4.55	508,498	$7.20	804,656	296,158	58.24%
8	Out-Season	67,570	$0.80	54,056	$0.80	54,056	$0.00	0	(54,056)	-100.00%
9	Total Demand	179,327		562,554		562,554		804,656	242,102	43.04%
10	Current Energy Charge									
11	In-Season	44,510,145	0.028375	1,262,975	0.035845	1,595,466				
12	Out-Season	16,043,665	0.028375	455,239	0.035845	575,085				
13	Total Energy	60,553,810		1,718,214		2,170,551				
14	Proposed Energy Charge									
15	In-Season									
16	First 164 kWh per kW	17,804,058					0.052513	934,944		
17	All Other kWh In-Season	26,706,087					0.050977	1,361,396		
18	Total In-Season							2,296,340	700,874	43.93%
19	Out-Season	16,043,665					0.055152	884,840	309,755	53.86%
20	Total Energy	60,553,810						3,181,180	1,010,629	46.56%
21	Annual Power Cost Update	60,553,810	0.00747	452,337		0	0.000000	0	0	0.00%
22	Total Revenue			2,846,148		2,846,148		4,118,201	1,272,053	44.69%

Idaho Power/1103
Witness: Scott D. Sparks

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Scott D. Sparks
Calculation of Revenue Impact − Schedule 24 (Transmission)

July 31, 2009

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
General Rate Case
Filed July 31, 2009

Agricultural Irrigation Service - Transmission
Schedule 24

Line No	Description	(1) Usage Blocks	(2) Current Base Rate	(3) Current Base Revenue	(4) Adjusted Base Rate	(5) Adjusted Base Revenue	(6) Proposed Base Rate	(7) Proposed Base Revenue	(8) Revenue Difference	(9) Percent Change
1	Service Charge									
2	In-Season	0.0	$102.00	0	$102.00	0	$128.00	0	0	0.00%
3	Out-Season	0.0	$3.00	0	$3.00	0	$3.00	0	0	0.00%
4	Total	0.0		0		0		0	0	0.00%
5	Minimum Charge	0.0	$3.00	0	$3.00	0	$3.00	0	0	0.00%
6	Demand Charge									
7	In-Season	0	$4.30	0	$4.30	0	$6.80	0	0	0.00%
8	Out-Season	0	$0.76	0	$0.76	0	$0.00	0	0	0.00%
9	Total Demand	0		0		0		0	0	0.00%
10	Current Energy Charge									
11	In-Season	0	0.026969	0	0.034439	0				
12	Out-Season	0	0.026969	0	0.034439	0				
1	Total Energy	0		0		0				
14	Proposed Energy Charge									
	In-Season									
16	First 164 kWh per kW	0					0.050453	0		
17	All Other kWh In-Season	0					0.048977	0		
	Total In-Season							0	0	0.00%
19	Out-Season	0					0.052989	0	0	0.00%
20	Total Energy	0						0	0	0.00%
21	Annual Power Cost Update	0	0.00747	0		0	0.000000	0	0	0.00%
22	Total Revenue			0		0		0	0	0.00%

Idaho Power/1104
Witness: Scott D. Sparks

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Scott D. Sparks
Calculation of Revenue Impact − Schedule 40

July 31, 2009

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
General Rate Case
Filed July 31, 2009

Unmetered General Service
Schedule 40

Line No	Description	(1) Usage Blocks	(2) Current Base Rate	(3) Current Base Revenue	(4) Adjusted Base Rate	(5) Adjusted Base Revenue	(6) Proposed Base Rate	(7) Proposed Base Revenue	(8) Revenue Difference	(9) Percent Change
1	Number of Billings	36.0								
2	Energy Charge									
3	Total Energy	12,900	0.052410	676	0.059880	772	0.074297	958	186	24.09%
4	Annaul Power Cost Update	12,900	0.007470	96		0	0.000000	0	0	0.00%
5	Total Revenue			772		772		958	186	24.09%

Idaho Power/1105
Witness: Scott D. Sparks

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Scott D. Sparks
Calculation of Revenue Impact − Schedule 41

July 31, 2009

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
General Rate Case
Filed July 31, 2009

Street Lighting Service
Schedule 41

Summary

Line No	Description	(1) Annual Lamps	(2) Current Base Rate	(3) Current Base Revenue	(4) Adjusted Base Rate	(5) Adjusted Base Revenue	(6) Proposed Base Rate	(7) Proposed Base Revenue	(8) Revenue Difference	(9) Percent Change
1	Company-Owned Non-Metered			99,505		105,542		118,643	13,101	12.41%
2	Customer-Owned Non-Metered			1,326		1,436		1,615	179	12.47%
3	Company-Owned Metered			0		0		0.00	0	0.00%
4	Customer-Owned Metered			0		0		0.00	0	0.00%
5	Total Bills	159								
6	Total kWh	823,084								
7	Annual Power Cost Update	823,084	0.007470	6,148		0	0.000000	0	0	0.00%
8	Total Revenue			106,979		106,978		120,258	13,280	12.41%
9	Wood Poles	6,568	1.90	12,479	1.90	12,479	1.90	12,479	0	0.00%
10	Steel Poles	720	7.39	5,321	7.39	5,321	7.39	5,321	0	0.00%
11	Underground Charges			320		320		320	0	0.00%
12	Total Revenue w/Facility Chgs			$125,099		$125,098		$138,378	13,280	10.62%

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
General Rate Case
Filed July 31, 2009

Street Lighting Service
Schedule 41

Company-Owned Non-Metered

Line No	Description	(1) Annual Lamps	(2) Current Base Rate	(3) Current Base Revenue	(4) Adjusted Base Rate	(5) Adjusted Base Revenue	(6) Proposed Base Rate	(7) Proposed Base Revenue	(8) Revenue Difference	(9) Percent Change
14	Sodium Vapor									
15	70 Watt	0	6.63	0	7.07	0	7.94	0	0	0.00%
16	100 Watt	10,082	6.58	66,340	7.02	70,760	7.89	79,547	8,787	12.42%
17	200 Watt	2,377	8.04	19,111	8.48	20,153	9.53	22,653	2,500	12.41%
18	250 watt	310	8.94	2,771	9.38	2,907	10.54	3,267	360	12.38%
19	400 Watt	1,002	11.26	11,283	11.70	11,722	13.15	13,176	1,454	12.40%
20	Total Sodium Vapor	13,771		99,505		105,542		118,643	13,101	12.41%
21	Company-Owned Non-Metered			$99,505		$105,542		$118,643	13,101	12.41%

Customer-Owned Non-Metered

Line No	Description	(1) Annual Lamps	(2) Current Base Rate	(3) Current Base Revenue	(4) Adjusted Base Rate	(5) Adjusted Base Revenue	(6) Proposed Base Rate	(7) Proposed Base Revenue	(8) Revenue Difference	(9) Percent Change
23	Sodium Vapor									
24	70 Watt	0	3.51	0	3.95	0	4.44	0	0	0.00%
25	100 Watt	12	3.68	44	4.12	49	4.63	56	7	14.29%
26	200 Watt	213	5.15	1,097	5.59	1,190	6.28	1,338	148	12.44%
27	250 watt	14	6.04	85	6.48	91	7.28	102	11	12.09%
28	400 Watt	12	8.36	100	8.80	106	9.89	119	13	12.26%
29	Total Sodium Vapor	251		1,326		1,436		1,615	179	12.47%
30	Customer-Owned Non-Metered			$1,326		$1,436		$1,615	179	12.47%

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
General Rate Case
Filed July 31, 2009

Street Lighting Service
Schedule 41

Company-Owned Metered

Line No	Description	(1) Annual Lamps	(2) Current Base Rate	(3) Current Base Revenue	(4) Adjusted Base Rate	(5) Adjusted Base Revenue	(6) Proposed Base Rate	(7) Proposed Base Revenue	(8) Revenue Difference	(9) Percent Change
32	Sodium Vapor									
33	70 Watt	0	5.45	0	5.45	0	6.12	0	0	0.00%
34	100 Watt	0	5.22	0	5.22	0	5.87	0	0	0.00%
35	200 Watt	0	5.32	0	5.32	0	5.98	0	0	0.00%
36	250 watt	0	5.50	0	5.50	0	6.18	0	0	0.00%
37	400 Watt	0	5.78	0	5.78	0	6.50	0	0	0.00%
38	Total Sodium Vapor	0		0		0		0	0	0.00%
39	Meter Charge	0	8.00		8.00		8.00	0	0	0.00%
40	Energy Charge									
41	Per kWh	0	0.040000		0.040000		0.044984	0	0	0.00%
42	Company-Owned Metered			$0		$0		$0	0	0.00%

Customer-Owned Metered

Line No	Description	(1) Annual Lamps	(2) Current Base Rate	(3) Current Base Revenue	(4) Adjusted Base Rate	(5) Adjusted Base Revenue	(6) Proposed Base Rate	(7) Proposed Base Revenue	(8) Revenue Difference	(9) Percent Change
44	Sodium Vapor									
45	70 Watt	0	2.55	0	2.55	0	2.86	0	0	0.00%
46	100 Watt	0	2.32	0	2.32	0	2.60	0	0	0.00%
47	200 Watt	0	2.43	0	2.43	0	2.73	0	0	0.00%
48	250 watt	0	2.60	0	2.60	0	2.92	0	0	0.00%
49	400 Watt	0	2.88	0	2.88	0	3.23	0	0	0.00%
50	Total Sodium Vapor	0		0		0		0	0	0.00%
51	Meter Charge	0	8.00	0	8.00	0	8.00	0	0	0.00%
52	Energy Charge									
53	per kWh	0	0.040000	0	0.040000	0	0.044984	0	0	0.00%
54	Customer-Owned Metered			$0		$0		$0	0	0.00%

Idaho Power/1106
Witness: Scott D. Sparks

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Scott D. Sparks
Calculation of Revenue Impact − Schedule 42

July 31, 2009

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
General Rate Case
Filed July 31, 2009

Traffic Control Signal Lighting Service
Schedule 42

Line No	Description	(1) Usage Blocks	(2) Current Base Rate	(3) Current Base Revenue	(4) Adjusted Base Rate	(5) Adjusted Base Revenue	(6) Proposed Base Rate	(7) Proposed Base Revenue	(8) Revenue Difference	(9) Percent Change
1	Number of Billings	72.0		0		0		0	0	0.00%
2	Energy Charge									
3	Total Energy	17,262	0.038500	665	0.045970	794	0.074265	1,282	488	61.46%
4	Annual Power Cost Update	17,262	0.00747	129		0	0	0	0	0.00%
5	Total Revenue			794		794		1,282	488	61.46%

Idaho Power/1107
Witness: Scott D. Sparks

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Scott D. Sparks
Typical Monthly Billing Comparisons – Schedule 24 (Secondary)

July 31, 2009

Idaho Power Company
Typical Monthly Billing Comparison
State of Oregon
General Rate Case

Schedule 24 - Secondary
Agricultural Irrigation Service
In-Season

Line No	Demand kW	Load Factor	Energy kWh	(1) Curr Rate	(2) Proposed Rate	(3) Difference (2) - (1)	(4) Percent Difference
1	10	20%	1,440	109.12	162.62	53.50	49.03%
2		35%	2,520	147.83	217.98	70.15	47.45%
3		50%	3,600	186.54	273.04	86.49	46.37%
4		65%	4,680	225.25	328.09	102.84	45.65%
5		80%	5,760	263.97	383.15	119.18	45.15%
6	50	20%	7,200	497.58	753.09	255.51	51.35%
7		35%	12,600	691.15	1,029.91	338.76	49.01%
8		50%	18,000	884.71	1,305.18	420.47	47.53%
9		65%	23,400	1,078.27	1,580.46	502.18	46.57%
10		80%	28,800	1,271.84	1,855.73	583.90	45.91%
11	100	20%	14,400	983.17	1,491.19	508.02	51.67%
12		35%	25,200	1,370.29	2,044.81	674.52	49.22%
13		50%	36,000	1,757.42	2,595.36	837.94	47.68%
14		65%	46,800	2,144.55	3,145.91	1,001.37	46.69%
15		80%	57,600	2,531.67	3,696.47	1,164.79	46.01%
16	300	20%	43,200	2,925.50	4,443.56	1,518.06	51.89%
17		35%	75,600	4,086.88	6,104.43	2,017.55	49.37%
18		50%	108,000	5,248.26	7,756.09	2,507.83	47.78%
19		65%	140,400	6,409.64	9,407.74	2,998.10	46.77%
20		80%	172,800	7,571.02	11,059.40	3,488.38	46.08%
21	500	20%	72,000	4,867.84	7,395.94	2,528.10	51.93%
22		35%	126,000	6,803.47	10,164.05	3,360.58	49.40%
23		50%	180,000	8,739.10	12,916.81	4,177.71	47.80%
24		65%	234,000	10,674.73	15,669.57	4,994.84	46.79%
25		80%	288,000	12,610.36	18,422.33	5,811.97	46.09%
26	750	20%	108,000	7,295.76	11,086.40	3,790.64	51.96%
27		35%	189,000	10,199.21	15,238.58	5,039.38	49.41%
28		50%	270,000	13,102.65	19,367.72	6,265.07	47.82%
29		65%	351,000	16,006.10	23,496.86	7,490.76	46.80%
30		80%	432,000	18,909.54	27,625.99	8,716.45	46.10%

In-season months include June, July, August, September

Rates include service charges

Idaho Power Company
Typical Monthly Billing Comparison
State of Oregon
General Rate Case

Schedule 24 - Secondary
Agricultural Irrigation Service
Out-Season

Line No	Demand kW	Load Factor	Energy kWh	(1) Current Rate	(2) Proposed Rate	(3) Difference 2-1	(4) Percent Difference
1	10	20%	1,440	62.62	82.42	19.80	31.62%
2		35%	2,520	101.33	141.98	40.65	40.12%
3		50%	3,600	140.04	201.55	61.51	43.92%
4		65%	4,680	178.75	261.11	82.36	46.07%
5		80%	5,760	217.47	320.68	103.21	47.46%
6	50	20%	7,200	301.08	400.09	99.01	32.88%
7		35%	12,600	494.65	697.92	203.27	41.09%
8		50%	18,000	688.21	995.74	307.53	44.68%
9		65%	23,400	881.77	1,293.56	411.78	46.70%
10		80%	28,800	1,075.34	1,591.38	516.04	47.99%
11	100	20%	14,400	599.17	797.19	198.02	33.05%
12		35%	25,200	986.29	1,392.83	406.54	41.22%
13		50%	36,000	1,373.42	1,988.47	615.05	44.78%
14		65%	46,800	1,760.55	2,584.11	823.57	46.78%
15		80%	57,600	2,147.67	3,179.76	1,032.08	48.06%
16	300	20%	43,200	1,791.50	2,385.57	594.06	33.16%
17		35%	75,600	2,952.88	4,172.49	1,219.61	41.30%
18		50%	108,000	4,114.26	5,959.42	1,845.16	44.85%
19		65%	140,400	5,275.64	7,746.34	2,470.70	46.83%
20		80%	172,800	6,437.02	9,533.27	3,096.25	48.10%
21	500	20%	72,000	2,983.84	3,973.94	990.10	33.18%
22		35%	126,000	4,919.47	6,952.15	2,032.68	41.32%
23		50%	180,000	6,855.10	9,930.36	3,075.26	44.86%
24		65%	234,000	8,790.73	12,908.57	4,117.84	46.84%
25		80%	288,000	10,726.36	15,886.78	5,160.42	48.11%
26	750	20%	108,000	4,474.26	5,959.42	1,485.16	33.19%
27		35%	189,000	7,377.71	10,426.73	3,049.02	41.33%
28		50%	270,000	10,281.15	14,894.04	4,612.89	44.87%
29		65%	351,000	13,184.60	19,361.35	6,176.76	46.85%
30		80%	432,000	16,088.04	23,828.66	7,740.62	48.11%

Rates include service charges

Idaho Power Company
Typical Monthly Billing Comparison
State of Oregon
General Rate Case

Schedule 24 - Secondary
Agricultural Irrigation Service
Weighted Average Monthly

Line No	Demand kW	Load Factor	Energy kWh	(1) Curr Rate	(2) Proposed Rate	(3) Difference (2) - (1)	(4) Percent Difference
1	10	20%	1,440	78.12	109.15	31.04	39.73%
2		35%	2,520	116.83	167.32	50.49	43.21%
3		50%	3,600	155.54	225.38	69.83	44.90%
4		65%	4,680	194.25	283.44	89.18	45.91%
5		80%	5,760	232.97	341.50	108.53	46.59%
6	50	20%	7,200	366.58	517.76	151.18	41.24%
7		35%	12,600	560.15	808.58	248.43	44.35%
8		50%	18,000	753.71	1,098.88	345.17	45.80%
9		65%	23,400	947.27	1,389.19	441.92	46.65%
10		80%	28,800	1,140.84	1,679.50	538.66	47.22%
11	100	20%	14,400	727.17	1,028.52	301.35	41.44%
12		35%	25,200	1,114.29	1,610.16	495.86	44.50%
13		50%	36,000	1,501.42	2,190.77	689.35	45.91%
14		65%	46,800	1,888.55	2,771.38	882.83	46.75%
15		80%	57,600	2,275.67	3,351.99	1,076.32	47.30%
16	300	20%	43,200	2,169.50	3,071.56	902.06	41.58%
17		35%	75,600	3,330.88	4,816.47	1,485.59	44.60%
18		50%	108,000	4,492.26	6,558.31	2,066.05	45.99%
19		65%	140,400	5,653.64	8,300.14	2,646.50	46.81%
20		80%	172,800	6,815.02	10,041.98	3,226.96	47.35%
21	500	20%	72,000	3,611.84	5,114.61	1,502.77	41.61%
22		35%	126,000	5,547.47	8,022.79	2,475.32	44.62%
23		50%	180,000	7,483.10	10,925.84	3,442.74	46.01%
24		65%	234,000	9,418.73	13,828.90	4,410.17	46.82%
25		80%	288,000	11,354.36	16,731.96	5,377.60	47.36%
26	750	20%	108,000	5,414.76	7,668.41	2,253.65	41.62%
27		35%	189,000	8,318.21	12,030.68	3,712.47	44.63%
28		50%	270,000	11,221.65	16,385.27	5,163.62	46.01%
29		65%	351,000	14,125.10	20,739.85	6,614.76	46.83%
30		80%	432,000	17,028.54	25,094.44	8,065.90	47.37%

In-season months include June, July, August, September

Rates include service charges

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE ________

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE IN THE STATE OF OREGON.	))))))

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

MICHAEL J. YOUNGBLOOD

July 31, 2009

Q. Please state your name, business address, and present occupation?

A. My name is Michael J. Youngblood 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 "Company") as the Manager of Rate Design in the Pricing and Regulatory Services Department.

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 Executive MBA program of Colorado State University. Over the years, I have attended numerous industry conferences and training sessions, including Edison Electric Institute's "Electric Rates Advanced Course."

Q. Please describe your work experience with Idaho Power.

A. I began my employment with 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 though is my experience within the Pricing and Regulatory Services 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 Services Department and have worked on special projects related to deregulation, the Company's Integrated Resource Plan, and filings with both the Idaho Public Utilities Commission ("IPUC") and the Oregon Public Utility Commission ("OPUC" or "Commission"). Specifically in Oregon, I have provided testimony to the Commission in Docket Nos. UE 123/UE 131, UM 1198, UM 1261, and UE 195.

In 2008, I was promoted to my current position of Manager of Rate Design for Idaho Power. It is in this position that I am currently responsible for the management of the rate design strategies of the Company as well as the oversight of all tariff administration.

Q. What is the scope of the testimony you are presenting in this case?

A. First, I will restate the Company's overall goals with regard to its rate design strategy in this proceeding and attest to the fact that the Company's proposed rate design will achieve these goals. I will also sponsor testimony and several exhibits presenting proposed modifications to the existing General Rules and Regulations section of the tariff as well as some proposed changes to service schedules not directly related to the Company's retail rate design. I will also sponsor an exhibit that summarizes the revenue impacts of this filing on all the Company's retail rate classes. That exhibit will illustrate the current and proposed effective revenues of each customer class as well as the requested percentage revenue increases. My last two exhibits will provide a complete set of the new proposed Tariff No. E-27, both in legislative format and in final form.

Q. Please provide a table of your exhibits.

A. The following list is a table of the exhibits which I will discuss in my testimony:

Exhibit 1201...............Rule B

Exhibit 1202...............Rule C

Exhibit 1203...............Rule D

Exhibit 1204...............Rule F

Exhibit 1205...............Rule G

Exhibit 1206...............Rule K

Exhibit 1207...............Rule L

Exhibit 1208...............Schedule 61

Exhibit 1209...............Schedule 62

Exhibit 1210...............Schedule 66

Exhibit 1211...............Schedule 90

Exhibit 1212...............Calculation of Revenue Impact – Summary

Exhibit 1213...............Proposed Tariff Sheets – Legislative Format

Exhibit 1214...............Proposed Tariff Sheets – Final Form

Q. What were the Company's overall objectives with regard to its rate design strategy?

A. Based upon conversations with Company witness Gregory Said and Company witness Timothy Tatum, we developed three overall objectives with regard to rate spread and rate design: (1) to establish prices that primarily reflect the costs of the services provided; (2) to have cost-based rate proposals designed to align with and encourage energy efficiency; and (3) to provide consistency and continuity throughout the Company's service territory. I directed Company witness Courtney Waites, Company witness Darlene Nemnich, and Company witness Scott Sparks to develop their rate design proposals in accordance with these objectives.

Q. How is the Company's cost-based objective being met in its rate design proposals?

A. As Mr. Tatum discussed in his testimony, the Company's primary approach to revenue requirement allocation in the last several general rate cases has been to establish class revenue requirements that reflect the costs of serving those customer classes as accurately as possible. The Company has consistently advocated for the principle that rate spread among the customer classes and component pricing within the customer classes should be primarily cost-based. Accordingly, the Company's ratemaking proposals have traditionally, and are once again in this case, advocating movement toward cost-of-service results. This objective has been met in previous proceedings and in this case by the rate design of seasonal rates for all metered service schedules, time-of-use rates for Large Power Service customers, and time-of-use rates for Large General Service customers taking service at both the Primary and Transmission service levels. In addition, this objective has been met by the implementation of rates that reflect a greater emphasis on the demand and customer related components, including the proposal for an on-peak demand charge for Large General Service customers, similar to that which is in place for the Large Power customers.

Q. How have the Company's rate design proposals been designed to encourage energy efficiency?

A. The Company is committed to providing customers cost-based price signals that encourage the wise and efficient use of energy. The cost-based rate design proposals presented in this case encourage increased energy efficiency for the Company's Residential Service, Large General Service, and Irrigation Service customer groups. Ms. Waites sponsors testimony and exhibits supporting the continuation of tiered rates for Residential Service customers, but with increased block sizes, and proposes a seasonal structure for both the summer and non-summer season. Ms. Nemnich sponsors testimony and exhibits supporting the expansion of the tiered summer rate for Small General Service customers to one that provides for a tiered structure in both the summer and non-summer seasons. The appropriate pricing signals are being provided for the Large General Service and Large Power Service customers by the time-of-use rates rate design I mention above; however, Ms. Nemnich has moved toward increasing the price differentials between the on-peak, mid-peak, and off-peak time blocks. And for Irrigation Service customers, Company witness Scott Sparks is sponsoring testimony and exhibits supporting the implementation of load-factor pricing.

Q. How do the Company's proposed rate designs meet the third objective?

A. The third objective of the rate design strategy was to provide consistency and continuity throughout the Company's service territory. The Company has both Idaho and Oregon jurisdictions. Many of the Company's customers move within the service territory and several have properties in both the Idaho and the Oregon jurisdictions. If large differences exist between the policies and procedures of the Company in each jurisdiction, it can be confusing and frustrating not only for customers but for Company personnel serving those customers. Throughout the Company's rate design and in the Rule modifications I am proposing, the desire to move toward consistency and continuity exists. There are situations and statutes that make complete uniformity impossible. However, whenever possible and appropriate, the Company has looked to move its rate design proposals and Rule modifications to be in alignment with those throughout its service territory.

Q. Will you be discussing every change you are proposing for the General Rules and Regulations and Service Schedules?

A. No. I will discuss all of the substantive changes to the General Rules and Regulations and affected Service Schedules; however, I have also made several changes that I consider "form" or "housekeeping" in nature only and do not change the scope, effect, or application of the various tariffs. I do not intend to discuss each of those changes at this time. They all are presented in the legislative format and final form in my last two exhibits.

<u>Rule B - Definitions</u>

Q. What is the change you are proposing for Rule B?

A. I am proposing the definition of "Billing Period" included in Rule B be changed to specify that while a typical billing period is 30 days, the normal billing period is considered to be 27 to 36 days. Rule B currently specifies a normal billing period to be 27 to 33 days.

Q. Why is this change being made?

A. As part of the Company's billing process, meter reading lists are prepared three days in advance of the read date. If a meter is installed for a customer, either due to a new service or as part of meter maintenance, three days or less before the scheduled read date for the route, the customer's meter will not be included on the meter reading list for that month's reading. When this situation occurs, the period of time between when the meter was installed and when it is read can exceed 33 days. When the number of days in the billing period exceeds the current upper limit of 33 days, the Service Charge, Basic Charge, and Demand Charge are prorated to recognize the longer billing cycle.

Q. How will extending the normal billing period to encompass 36 days be beneficial?

A. Extending the normal billing period to encompass 36 days will minimize the number of bills that include prorated billing components. The reduced number of prorated bills will reduce customer dissatisfaction, the number of calls received in the Company's Customer Service Center, and Company workload.

Q. Will the implementation of Advanced Metering Infrastructure ("AMI") negate the need for this change?

A. No. The implementation of AMI will have no affect on the billing period length. Billing period only determines the window in which a Read Day should occur. A longer billing period will still be needed after installation of AMI.

Q. Are any other Service Schedules or General Rules and Regulations affected by this change to Rule B?

A. Yes. Schedule 7 and Schedule 9 include references to the number of days in a billing period for purposes of determining service eligibility. The language in the "Applicability" section for each of these schedules has been revised to reflect the upper limit of 36 days for a normal billing cycle. In addition, the Fractional Periods section in Rule G has been modified slightly for clarification and to explicitly show the billing period number of days.

Rule C – Service and Limitations

Q. Please describe the changes you are proposing to Rule C.

A. I am proposing to delete the current Section 4, "Service Agreement" and eliminate pages 3 and 4 of Rule C which contain the Uniform Service Agreement.

Q. What is the history behind the Uniform Service Agreement?

A. Prior to June 1, 2005, customers eligible for service under Schedule 19, Large Power Service were required to sign a Uniform Large Power Service Agreement with the Company in order to receive service under Schedule 19. If the customer refused to sign the Agreement, the Company continued to provide service under Schedule 9, Large General Service, although the customer was not technically eligible for service under Schedule 9. In order to ensure that customers were placed on the appropriate service schedule based on their usage characteristics, the Company, as part of its general rate case filing in Docket No. UE 167, proposed to eliminate the requirement that a Uniform Large Power Service Agreement be signed in order to receive service under Schedule 19. The OPUC approved the Company's proposal in that proceeding.

Q. Were any other contracting provisions approved at that time?

A. Yes. As part of that same case, the Company proposed, and the Commission approved, what is now the Rule C Service Agreement provision.

Q. What is that provision?

A. Under Rule C, Section 4, “Service Agreement,” service to all loads equal to or in excess of 1,000 kilowatts (“kW”) at a single point of delivery is subject to pre-approval by the Company through a written and signed Uniform Service Agreement between the customer and the Company. This provision was intended to provide the Company with useful information for its planning purposes and the customer with certainty that the facilities are in place to provide the agreed upon level of capacity.

Q. Why are you now proposing to eliminate the Uniform Service Agreement?

A. There are several factors that influenced the Company’s decision to eliminate the Uniform Service Agreement. First, agreements specifying a contracted level of demand no longer provide value from a planning perspective. The Company, through new technologies, can monitor network utilization of individual transformers, feeders, and substations to provide valuable information for its planning purposes. Second, several customers have expressed that they see no value in the Uniform Service Agreement and have chosen not to enter into one. With both the Company and customers seeing little to no value being provided by the Agreement, it makes sense to eliminate the requirement that one be signed.

Q. Are you proposing any other changes to the General Rules and Regulations as a result of your proposal to eliminate the Uniform Service Agreement?

A. Yes. In order to provide the Company the same protection currently included in the Uniform Service Agreement, additional language will need to be added to Rule K, Customer’s Load and Operations. I will discuss this additional language in the Rule K section later in my testimony.

Q. Are you proposing any other changes to Rule C?

A. Yes. Under "Service Application," I am including wording to allow the Company to accept applications for service through the Company's website. This change aligns Rule C with current practices.

<u>Rule D – Metering</u>

Q. Please describe the proposed substantive changes to General Rule D.

A. I am proposing to insert a new Section D, "Surge Protection Device Services." Surge Protection Device Services is a proposed optional service that allows watt-hour metered customers to request installation or removal of whole-house surge protection devices. The surge protection devices are not owned by the Company and must be customer-provided, certified by Underwriters' Laboratories, Inc., and meet National Electric Energy Testing, Research and Application Centers ("NEETRAC") test standards or comparable test standards. In addition, the Company must be provided proof that the vendor of the surge protection device has executed and delivered to the Company an agreement that provides for the full defense and indemnification of the Company by the vendor against any claims, suits, or losses associated with such device.

The addition of this section provides for charges associated with customer-requested installation, removal, and assessment of surge protection devices. The charges are designed to cover the costs Idaho Power will incur when Company personnel respond to a customer request for installation, removal, or assessment of surge protection devices.

Surge Protection Device Services is an optional service currently being offered to watt-hour metered customers in the Company's Idaho retail jurisdiction. The Company proposes to extend this optional service to qualifying Oregon customers.

Q. Where can customers purchase whole-house surge protection devices?

A. Various retailers and third-parties sell whole-house surge protection devices.

Q. Can anyone other than Idaho Power personnel install or remove surge protectors?

A. Yes, licensed electricians can perform these services.

Q. What charges are you proposing under the Surge Protection Devices Service?

A. I am proposing a Surge Protection Device Installation or Removal Charge of $43 and a Surge Protection Device Customer Visit Charge of $25. Both charges are outlined in the proposed changes to Schedule 66.

Q. When would the proposed Surge Protection Device Installation or Removal Charge be applicable?

A. In the event Idaho Power personnel install or remove a surge protection device, the customer would be charged the Surge Protection Device Installation or Removal Charge of $43.

Q. When would the proposed Surge Protection Device Customer Visit Charge be applied?

A. The proposed Surge Protection Device Customer Visit Charge would apply when Company personnel are dispatched at the customer's request to install the surge protection device but find that they cannot do so due to safety concerns or lack of access to the meter base or other utility access points.

Likewise, a Surge Protection Device Customer Visit Charge would be charged to customers requesting on-site visits to assess alleged electrical problems related to a surge protection device but where no problems associated with the electrical service are found.

<u>Rule F – Service Connection and Discontinuance</u>

Q. Please describe the proposed substantive changes to General Rule F, Service Connection and Discontinuance.

A. The Company is proposing to change the title of Rule F to "Service Establishment and Discontinuance" to more clearly identify the activities required for initiating and terminating service. In addition, the Company proposes to implement a provision for Service Establishment and Continuous Service.

Q. Please describe the Service Establishment provision.

A. Service Establishment describes the condition where a customer desires to activate an account with the Company and the service is currently energized. When a customer contacts the Company and requests service at a specified service point, the Company will determine whether the requested service point is currently energized. If the service point is energized, the Company performs the work necessary to establish a new customer account; the customer's name, address, and other pertinent information are entered or updated into the Customer Information System and the Company dispatches personnel to the service point to collect an initial meter read. The Company proposes to recover the cost of these tasks by charging a Service Establishment Charge.

Q. What is the Company's reasoning for proposing a Service Establishment Charge?

A. The proposed Service Establishment Charge reflects the costs of performing the tasks outlined above. These costs must either be borne by all customers or by those actually receiving the service. In fairness to its customers and aligned with the Company's previously stated rate design goals, the Company's proposal targets expense recovery from those who are actually creating the costs.

Q. Will the Service Establishment Charge apply if a customer requests service establishment at a non-metered service point?

A. No. The Service Establishment Charge is not applicable to non-metered service points. Non-metered service points such as cable TV power supplies, telephone booths, street lighting, etc., are unique in respect to the degree of account establishment, work which I described above, the Company may perform. In particular, no meter reading is required. Therefore, the costs to establish service for non-metered accounts are recovered through the standard service schedule charges.

Q. What if the customer requests service at a location where the service line is not currently energized?

A. Service Connection describes the condition where service was once energized, has been disconnected, and is presently requested by the customer to be re-energized. The Service Connection Charge reflects the costs of tasks performed to physically reconnect the service and update the pertinent information in the Customer Information System.

Q. Will a customer be charged both the Service Establishment Charge and the Service Connection Charge?

A. No. The Service Connection Charge includes the costs associated with the tasks of service establishment plus the costs of physically reconnecting a service line.

Q. What are the fees associated with these transactions?

A. The Service Establishment Charge is $20 for all metered service points. The Service Connection Charge varies with the skill level required of the employee dispatched to perform the work. The skill level required is determined by the line voltage typically serving the customer class. Customers taking service under Schedules 1, 7, and 9 who request reconnection during normal business hours will be charged $20. Customers taking service under Schedules 15, 19, 24, 40, 41, and 42 who request reconnection during normal business hours will be charged $40. The higher fee for the latter schedules represents the required expertise of the dispatched employee to work with the typically higher voltage at the point where service is reconnected. Both the proposed Service Establishment Charge and the Connection Charges are delineated in the Company's Schedule 66.

Q. Are you proposing any additional changes to Rule F?

A. Yes. I am proposing to add a new section for Continuous Service.

Q. Why are you proposing to add a new section on Continuous Service?

A. In order to more equitably recover the costs associated with providing services offered to property managers under the Continuous Service Program, the Company proposes to implement a Continuous Service Reversion Charge of $10 per transaction. This proposed charge would be defined within Rule F and the amount listed under Schedule 66.

Q. Please describe how the Company operates its Continuous Service Program.

A. The Continuous Service Program provides property managers the option to have electric service at their properties automatically transfer into their names when tenants request service to be discontinued. Under the Company's current practice, each time a customer requests electric service to be discontinued at a location listed under a Continuous Service Program arrangement, the service remains connected and the financial responsibility for the service is shifted from the customer requesting the disconnection to the property manager. Currently, property managers are not assessed a charge when service is transferred into their names.

Q. What initially drove the Company's decision to provide services under the Continuous Service Program without a direct charge assessed to property managers?

A. The services provided under the Continuous Service Program have been offered without a direct charge to property managers in an effort to encourage participation in the program and to recognize the program's operational benefits.

The Continuous Service Program has helped the Company to utilize its personnel more effectively and efficiently and has contributed to a higher level of customer satisfaction. For instance, the Company's metering department is provided added flexibility in its scheduling of connections and disconnections through this program. During the transitioning of tenants, the Company must simply obtain a meter reading for billing purposes rather than connecting and disconnecting service. This still requires a visit to the service address resulting in little or no reduction in costs. However, metering personnel are able to prioritize their work around a fewer number of service connections and disconnections.

The Continuous Service Program has also reduced the need for property managers to contact the Company's Customer Service Center each time a tenant wishes to discontinue service. As a result, Company representatives are available to serve other customer needs.

Q. Why is the Company now proposing to implement a Continuous Service Reversion Charge for customers enrolled in the Continuous Service Program?

A. The original intent of the Continuous Service Program was to provide a service under which property owners and managers could have the electric service at their properties remain connected between tenants in order to prevent winter damage and have electricity available for maintenance and/or marketing of the property. The Company determined that the potential operational benefits associated with the program would justify offering the service at no direct charge. However, based upon continued customer input and operating experience, the Company has implemented additional services over time not offered under the original Continuous Service Program design. Specifically, under the Continuous Service Program, the Company now notifies the property manager in writing each time financial responsibility is transferred into their name, electric service to the property is subject to termination, or application for electric service to the property is denied. The Company also mails, annually, an inventory of all the properties listed under the Continuous Service Program arrangement to property managers.

Each of the new services offered under the Continuous Service Program has added to the operating costs of the program. Considering that the costs of offering the program have increased while the operational benefits have remained unchanged, the Company has determined that the Continuous Service Reversion Charge should be implemented to move toward more equitable cost recovery by charging only those customers who benefit from these services rather than spreading the costs among all ratepayers.

Q. How did the Company determine that $10 was the appropriate amount for the Continuous Service Reversion Charge?

A. In setting the appropriate amount for the Continuous Service Reversion Charge, the Company used the current Service Establishment Charge as the basis for the determination. The Service Establishment Charge recovers the costs associated with recording the customer's pertinent information into the Company's customer information system and retrieving and recording the initial meter reading. In order to continue to provide a financial incentive for participation in the Continuous Service Program, it was determined that the Continuous Service Reversion Charge should be lower than the proposed Service Establishment Charge. Fifty percent of the Service Establishment Charge, or $10, was determined to be a reasonable charge that would offset a portion of the costs of operating the program while still maintaining an incentive to encourage participation.

Q. Are you proposing other changes to Rule F?

A. Yes, I am proposing to add language to the "Service Discontinuance" section to address the Service Establishment Charge.

Q. What language was added in the "Service Discontinuance" section of Rule F?

A. Currently, subsection "a." of the "Service Discontinuance" section states that "When a customer requests service to be discontinued, service will not be disconnected if another party has agreed to accept responsibility for service at the Point of Delivery." Here, clarifying language has been added to indicate "Upon initiating service, the Customer requesting service will be billed a Service Establishment Charge in accordance with this rule."

Rule G - Billings

Q. What changes are you proposing for Rule G?

A. The minor change to Rule G is for clarity and in response to the change in the definition of "Billing Period" the Company is proposing to be made in Rule B. The change to Rule G clarifies that "Fractional Periods" are when the customer's Billing Period is less than 27 days or greater than 36 days.

Rule K – Customer's Load and Operations

Q. Are you proposing any other changes to the General Rules and Regulations?

A. Yes. As a result of the Company's proposal to eliminate the Uniform Service Agreement, it is necessary to make some modifications to Rule K. The terms and conditions of the current Uniform Service Agreement provide the Company the ability to require the customer to pay for any damages that may be caused due to the customer taking power in excess of the amount stated in the Agreement. In order to provide this same ability to the Company in the future, language has been added to Rule K, Section 3, "Change of Load Characteristic." This section of Rule K currently requires customers to provide prior notice before making any significant change in either the amount or electrical character of their loads. The new language added to this section continues to provide the Company the same protection currently included in the Uniform Service Agreement and clarifies for all customers the potential consequence of failing to provide prior notice of change in electrical load.

Q. What other changes are you proposing to Rule K?

A. In addition to the change I just described, I am proposing three other changes to Rule K. The first change is relatively minor and regards the section on "Practices and

Requirement for Harmonic Control." Language in Section 2 currently references the Institute of Electrical and Electronic Engineers ("IEEE") Standard 519-1992. I am proposing that this language be changed to no longer refer to a specific edition of the IEEE 519 standard, i.e., the 1992 edition, but rather to the current edition. This change will allow the Company to implement the current standard as updates are made without having to make a tariff filing with the Commission.

Q. What is the second change you are proposing to Rule K?

A. I am proposing language in the "Protection of Electrical Equipment" section be modified to reflect the advancements made in modern electronics. The proposed updated language for Section 4 addresses the need for customers to adequately protect not only their equipment and property but also their data, operations, and work from disturbances on the electrical system. Such disturbances may include high and low voltages, surges, harmonics, transients in voltage, singe phasing conditions, reversal of phase rotation, and phase unbalance.

Q. What is the third change you are proposing to Rule K?

A. I am adding language that specifically states that the Company must approve the connection to the Company's system of all motors greater than 7 ½ horsepower in order to ensure that adequate facilities are installed to limit the effects of flicker, voltage balance, voltage level, or reactive power, to name a few, that may be caused by the motor. If changes are necessary to the Company's facilities in order to prevent a motor installation from affecting the Company's system, the proposed language specifies that the customer installing the motor may be required to pay the costs associated with the additional facilities. In addition, I have made changes to the "Allowable Locked Rotor Currents" table included in Rule K to clarify the starting currents that are allowed for different size motors and to more clearly specify that if no starting current value is shown in the table for a specific size motor, the Company must approve the starting current prior to motor installation.

Q. What is the overall purpose for these modifications to Rule K?

A. The overall purpose is to incorporate into the Company's Rules and Regulations recognition of the sensitive nature of modern loads, the impacts these loads can have on the Company's system and other customers, and customers' responsibilities regarding their loads and operations in order to address potential power quality issues.

<u>Rule L – Deposits</u>

Q. Are there any changes the Company is proposing for Rule L?

A. Yes. The Company is proposing the addition of language to Rule L – Deposits, Section (1), "Residential Customers." The additional language is being proposed to better tie the deposit requirements of a residential customer to OAR 860-021-0200. Oregon Administrative Rules state that an applicant or customer may be required to pay a deposit at the time of application for new or continued service when the applicant or customer is unable to establish credit as defined in Section 1 of OAR 860-021-0200. With this change, Rule L will explicitly state the deposit requirements of a residential customer as defined by the Oregon Administrative Rules.

Q. Is the Company proposing any additional substantive changes to its General Rules and Regulations at this time?

A. No. I have discussed all of the substantive changes to the General Rules and Regulations. As I stated before, I have made several changes that I consider "form" or "housekeeping" in nature only and do not change the scope, effect, or application of the various tariffs. They all are presented in the legislative format and final form in my last two exhibits. However, in addition to the proposed changes to General Rules and Regulations, I do have some proposed changes to the Company's tariff schedules which are not directly related to the Company's retail rate design.

Q. To which of the Company's tariff schedules are you proposing modifications?

A. I am proposing changes to Schedules 61, 62, 66, and 90.

Schedule 61 – Power Quality Program

Q. What changes are you proposing for Schedule 61?

A. For Schedule 61, I am proposing to modify language in the "Home Wiring Audit" section, add a "Purpose of Payment" section, and delete the "Financing" section.

Q. Please explain the changes you are proposing to the "Home Wiring Audit" section.

A. When Schedule 61 was first approved by the Commission in 1993, the Company was operating a Power Quality Program. Electricians who took specific courses could become an "approved" participant in the Company's program. Customers who had a home wiring audit performed by an approved electrician were eligible to receive a Home Wiring Audit payment. It has now become standard practice for licensed electricians to be trained to perform home wiring audits and the Company's Power Quality Program is no longer needed to encourage this training. However, the payment provided to customers under Schedule 61 when a home wiring audit is performed continues to be beneficial. Changes are being proposed to the "Home Wiring Audit" section of Schedule 61 and an additional "Purpose of Payment" section is being added to provide clarity on the purpose of the payment and the steps customers can take to receive a payment for a home wiring audit. In addition, the amount of the payment to customers for a home wiring audit is proposed to increase from the $25 established in 1993 to $40 to more accurately reflect the increase in electrician fees over the past 15 years.

Q. Please explain why the Company is proposing to remove the "Financing" section from Schedule 61.

A. Another aspect of the Power Quality Program that has been offered to Customers since its implementation in 1993 is financing for the purchase of equipment or repairs to correct power quality problems. When the Company reorganized in 1996, it started moving away from offering financing for programs of this type but did not eliminate the loan options for the Power Quality Program. At that time, the Company had recently added harmonic limits to Rule K and it wanted customers to have an option for purchasing harmonic filtering equipment. Since then, Customer interest in the financing option has diminished. Furthermore, with the current economic conditions, the Company is getting out of financing options for customers and employees as well. For this reason, the Company is proposing to remove the "Financing" section from Schedule 61.

<u>Schedule 62 – Green Energy Purchase Program Rider</u>

Q. Please describe the proposed changes to Schedule 62.

A. The changes to Schedule 62 are not substantive, but do need to be discussed to provide some background for the proposed change. The Company is proposing to add language to the schedule to allow the participation of "non-customers" in the optional Green Energy Purchase Program. The primary reason for proposing the additional language at this time is to help align and make more consistent the Company's schedules throughout its service territory.

Q. Why is the Company proposing to add the language for "non-customers" for Schedule 62?

A. The situation arose within the Company's Idaho jurisdiction that some participants of the Green Energy Purchase program wanted to continue contributing to the program even after they had moved out of the jurisdiction. While the language present in the Idaho tariff would meet the need of any non-customer, the Company is proposing, for consistency, to include it in the Oregon schedule as well.

<u>Schedule 66 – Miscellaneous Charges</u>

Q. Please describe the proposed changes to Schedule 66.

A. As previously discussed in the changes proposed to Rule F, the Company proposes to include a $20 Service Establishment Charge and a $10 Continuous Service

Reversion Charge under Schedule 66. In addition, two Surge Protection Device Services Charges are proposed for inclusion in this schedule. Lastly, the charge for Primary Metering under Rule D is changing from Actual Cost to Work Order Cost.

Q. What are the proposed Surge Protection Device Services Charges being added to Schedule 66?

A. Both a Surge Protection Device Installation or Removal Charge of $43 and a Surge Protection Device Customer Visit Charge of $25 are being proposed as a result of the proposed changes to Rule D discussed earlier in my testimony.

Q. Why is the charge for Primary Metering under Rule D changing from Actual Cost to Work Order Cost?

A. When a customer specifically requests instrument transformer metering that is not required by the Company, the cost of such metering equipment and its installation is paid by the customer. Customers must make payments prior to the work being performed. Because prepayment is required, it is inconsistent to base the charges on "actual labor, time, and mileage costs." Therefore the proposed tariff text has been modified to state the charges will be based on the Company's Work Order Cost, which is the designed cost estimate, including labor, time, and mileage.

<u>Schedule 90 – Direct Access Pilot Program Energy Service</u>

Q. What changes are you proposing for Schedule 90?

A. I am proposing to discontinue Schedule 90, Direct Access Pilot Program Energy Service. Schedule 90 was put in place in 1998 shortly after direct access was approved in Oregon to make it possible for Idaho Power to provide direct access should an eligible customer request it. However, this is a service that is no longer needed. In an effort to keep the Company's tariff schedules current, I am proposing to discontinue Schedule 90.

<u>Schedule 19 – Reduction in Large Power Service Eligibility Requirements</u>

Q. Is the Company proposing to make changes in the eligibility requirements for service under Schedule 19, Large Power Service?

A. Yes. Idaho Power is proposing to change the eligibility requirements of Schedule 19, Large Power Service customers. Currently, if the aggregate power requirement of a customer who receives service at one or more points of delivery on the same premise exceeds 25,000 kW, the customer is required to make special contract arrangements with the Company. Idaho Power is proposing that the level at which a customer is required to make special contract arrangements with the Company be lowered to 20,000 kW.

Q. Why does Idaho Power want to reduce the upper limit of power requirement for Large Power Service from 25,000 kW to 20,000 kW?

A. Idaho Power is proposing to lower the upper limit of eligibility for Large Power Service customers so that the Company can manage new loads more effectively and provide more protection to other retail customers from the system impacts large loads may impose on the system. At a time when the ability of the Company's system to serve new load is constrained, the sheer size and operating characteristics of the new load can be expensive to serve. By lowering the size limit, Idaho Power can treat these larger loads within a special contract, which allows for specific cost-of-service information to be determined and reviewed during regulatory proceedings. This allows for the unique characteristics of customers of this size to be captured within the terms of a contractual agreement.

Q. Does Idaho Power currently have any Large Power Service customers taking service under Schedule 19 whose power requirement is greater than 20,000 kW?

A. No. In fact, upon review of the highest monthly kW demand of Idaho Power's largest 10 customers for the previous five years, the largest customer's maximum monthly billing demand did not even reach 18,000 kW.

Q. What does the Company propose for future customers whose power requirement exceeds 20,000 kW?

A. Any future customer who applies for service over 20,000 kW of aggregate load would adhere to the same interconnection procedures as currently required for new load over 25,000 kW.

Q. If the Company's proposal is adopted, what will happen to any existing customer whose power requirement grows to exceed 20,000 kW?

A. Any existing customer whose power requirements grow and exceed the new cap of 20,000 kW will no longer be eligible for service under Schedule 19. They would be required to make special contract arrangements with the Company, just as is currently required if a customer's power requirements exceed 25,000 kW.

Q. Is this reduction in the upper limit of the power requirement consistent with the Company's regulatory goals?

A. Yes. Because Idaho Power will be able to better determine the additional costs of serving specific large loads, the reduction in the power requirement eligibility limit is consistent with Idaho Power's regulatory goals. These goals are:

1. Provide requested service consistent with system capability and the reliability needs of existing customers;

2. Provide options to the customer when the Company is unable to provide service as requested;

3. Mitigate the rate impact on existing customers by developing a rate structure that includes a marginal price component for an initial term of the service agreement;

4. Require upfront contributions to capital expenditures associated with facilities that specifically serve the customer; and

5. Provide a means to quantify known and measurable amounts of additional load for Integrated Resource Planning.

Q. How does reducing the power requirement limit to 20,000 kW help mitigate the rate impact of potential new large load customers on existing customers?

A. Because the new load will be required to make special contract arrangements with the Company, Idaho Power can more accurately price the new load based on its unique characteristics, thus mitigating the impact on existing customers. For example, under a special contract, the parties can negotiate a price that reflects a blend of marginal and embedded costs, or the flexibility to offer the new customer pass through access to market rates, depending on the resources required to serve the new load. Or, the parties could agree to allow the Company to shape the load or service requirements in response to resource limitations or transmission constraints during system peaks.

Q. Have you made the proposed language changes to Schedule 19?

A. Yes. The changes required to reduce the eligibility requirement for Large Power Service from 25,000 kW to 20,000 kW have been made to Schedule 19, along with the other changes made to that schedule described in Ms. Nemnich's testimony.

Q. What other exhibits are you sponsoring?

A. Exhibit 1212 is the Calculation of Revenue Impact – Summary. This table indicates that the overall average increase over the Adjusted Base Rates is 22.6 percent.

Q. What are the Adjusted Base Rates?

A. As Mr. Said described in his testimony, for purposes of determining the jurisdictional revenue requirement, the Company has utilized the normalized power supply expenses from the 2008 October Update. Therefore, the associated revenues from the 2008 October Update are included as well in determining the Company's Revenue Deficiency and Revenue Requirement. Mr. Tatum used this information to allocate the required revenue to each class. The Adjusted Base Rates reflect the Company's current base retail rates plus the October Update portion of the Annual Power Cost Adjustment ("APCU").

Q. How were the Adjusted Rates determined for each Service Schedule?

A. The APCU is recovered as a kilowatt-hour charge. The 2008 October Update portion of the APCU is 0.7470 cents per kilowatt-hour. The adjusted energy charge for each of the metered schedules simply added the base rate energy charge plus the APCU amount of 0.7470 cents. The resulting revenue is the Adjusted Base Revenue. These numbers are reflected in the exhibits of Ms. Waites, Ms. Nemnich, and Mr. Sparks and on my Exhibit No. 1212, Calculation of Revenue Impact – Summary.

Q. What are your last two exhibits?

A. My last two exhibits are a complete set of the Company's proposal for Tariff No. E-27. The changes I have proposed within my testimony, along with the rate and design changes proposed by Ms. Waites, Ms. Nemnich, and Mr. Sparks, are reflected in the pages of these two exhibits. Exhibit No. 1213 is presented in legislative format for ease of reviewing the Company's proposed changes and modifications. Exhibit No. 1214 is the tariff in final form.

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

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Michael J. Youngblood
Rule B

July 31, 2009

RULE B
DEFINITIONS

The terms listed below, which are used frequently in this Tariff, will have the stated meanings:

Billing Period is the period intervening between meter readings and shall be approximately 30 days. However, Electric Service covering 27-~~33~~ 36 days inclusive will be considered a normal Billing Period.

Commission refers to the Oregon Public Utility Commission.

Company refers to Idaho Power Company.

Customer is the individual, partnership, association, organization, public or private corporation, government or governmental agency receiving or contracting for Electric Service. Customer status may be retained when a Customer voluntarily disconnects and subsequently requests service from the Company within 20 days as provided by OAR 860-021-0008.

Demand is the average kilowatts (kW) or horsepower (HP) supplied to the Customer during the 15-consecutive-minute period of maximum use during the Billing Period, as shown by the Company's meter, or determined in accordance with the demand clause in the schedule under which service is supplied. In no event, however, will the maximum demand for the Billing Period be less than the demand determined as specified in the schedule.

Electric Service is the availability of power and energy in the form and at the voltage specified in the Oregon Electric Service Application or agreement, irrespective of whether electric energy is actually utilized, measured in kilowatt-hours (kWh).

Month (unless calendar month is stated) is the approximate 30-day period coinciding with the Billing Period.

Normal Business Hours are 8:00 a.m. to 5:00 p.m., Monday through Friday, excluding holidays observed by the Company. Notices of office closures for holidays are posted, in advance, at the Company office entrances.

Point of Delivery is the junction point between the facilities owned by the Company and the facilities owned by the Customer; OR the Point at which the Company's lines first become adjacent to the Customer's property; OR as otherwise specified in the Company's Tariff.

Power Factor is the percentage obtained by dividing the maximum demand recorded in kW by the corresponding kilovolt-ampere (kVA) demand established by the Customer.

Premises is a building, structure, dwelling or residence of the Customer. If the Customer uses several buildings or structures in the operation of a single integrated commercial, industrial, or institutional enterprise, the Company may consider all such buildings or structures that are in proximity to each other to be the Premises, even though intervening ownerships or public thoroughfares exist.

RULE B
DEFINITIONS
(Continued)

Service Level is defined as follows:

Secondary Service is service taken at 480 volts or less, or when the definitions of Primary Service and Transmission Service do not apply. The Company is responsible for providing the transformation of power to the voltage at which it is to be used by the Customer taking Secondary Service.

Primary Service is service taken at 12.5 kilovolts (kV) to 34.5 kV. Customers taking Primary Service are responsible for providing the transformation of power to the voltage at which it is to be used by the Customer.

Transmission Service is service taken at 44 kV or higher. Customers taking Transmission Service are responsible for providing the transformation of power to the voltage at which it is to be used by the Customer.

Idaho Power/1202
Witness: Michael J. Youngblood

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Michael J. Youngblood
Rule C

July 31, 2009

RULE C
SERVICE AND LIMITATIONS

1. Rates and Tariff. Service supplied by the Company will be in accordance with the Tariff on file with the state regulatory authority having jurisdiction, and as in effect at the time service is supplied. All service rates and agreements are subject to the continuing jurisdiction and regulation of such authority, as provided by law. Those matters relating to customer service not expressly addressed in the Rules, Regulations, and Rates of this Tariff shall conform to the requirements of Oregon Administrative Rules, Chapter 860, Division 21.

When any municipal corporation or other local taxing agency imposes on the Company any franchise, occupation, sales, license, excise, business, operating, privilege, or use of street tax or exaction, the amount thereof which exceeds 3 1/2 percent of the gross revenue (pursuant to OAR 860-22-0040) derived from Electric Service furnished Customers within the levying municipality or taxing district will be billed pro rata to such Customers in accordance with Schedule 95. When Customers are billed as herein provided, the amount will be separately stated on, and added to, the regular billing.

2. Supplying of Service. Service will be supplied under a given schedule only to Points of Delivery as are adjacent to facilities of the Company, adequate and suitable as to capacity and voltage for the service desired and under the schedule applicable thereto. The Company will not be obligated to construct extensions or install additional service facilities except in accordance with Rule H. In all other cases, special agreements between the Customer and the Company may be required.

3. Service Application. The Company will normally accept an application for service from the Customer by telephone, through the Company's website or by other oral communication. The Company may however, at its discretion, require the Customer to sign an application requesting service. As provided in OAR 860-021-0055, applications for temporary, seasonal, or short-term service for periods of not less than one month are accepted when the Company has available capacity for the service required and the Customer pays the Company in advance the estimated net cost of installing and removing the facilities required to supply service.

~~4. Service Agreement. Service to all loads equal to or in excess of 1,000 kW Demand at a single Point of Delivery are subject to preapproval by the Company through a written and signed Uniform Service Agreement between the Customer and the Company. The Company cannot guarantee the availability of power equal to or in excess of 1,000 kW to Customers who have not entered into a written Uniform Service Agreement.~~

4~~5~~. Choice of Schedules. The Company's schedules are designed to provide monthly rates for service supplied to the Customer on an annual basis. The Customer may elect to take service under any of the schedules applicable to this annual service requirement, and the Company will endeavor to assist in the selection of the appropriate schedule most favorable to the Customer. Changing of schedules will occur only when the characteristics of the Customer's usage change such that another applicable schedule is deemed more favorable to the Customer when applied to the Customer's annual service requirements. Customers receiving service under Schedules 7, 9, and 19 will be reviewed on a monthly basis under the provisions established in the Applicability section of each of these schedules.

5~~6~~. Point of Delivery Service Requirements. A Customer may be served at more than one Point of Delivery at the same Premises if practicable, unless otherwise specified in a schedule. Service at each Point of Delivery at the same Premises will be offered under the appropriate schedule. The Customer's request for service at an additional Point of Delivery will be subject to the applicable line extension rules of the Company. The Company may refuse to provide service at more than one Point of Delivery at the same Premises if it is determined by the Company that the additional Point of Delivery cannot be provided without jeopardizing the safety and reliability of the Company's system or service to the Customer or to other Customers. Service provided to a Customer at multiple Points of Delivery at the same Premises will not be interconnected electrically.

RULE C
SERVICE AND LIMITATIONS
(Continued)

Point of Delivery Service Requirements (Continued)

Where separate Points of Delivery exist for supplying service to a Customer at a single Premises or separate meters are maintained for measurement of service to a Customer at a single Premises, the meter readings will not be combined or aggregated for any purpose except for determining if the Customer's total power requirement exceeds ~~25~~20,000 kW. Special contract arrangements will be required when a Customer's aggregate power requirement exceeds ~~25~~20,000 kW.

Service delivered at low voltage (600 volts or under) will be supplied from the Company's distribution system to the outside wall of the Customer's building or service pole, unless an exception is granted by the Company and the City or State Electrical Inspector.

The Customer's facilities will be installed and maintained in accordance with the requirements of the National Electrical Code.

6~~7~~. Limitation of Use. A Customer will not resell electricity received from the Company to any person except where the Customer is owner, lessee, or operator of an apartment house, mobile home court, or other multi-family dwelling where the use has been sub-metered prior to January 1, 1974, and the use is billed to residential tenants at the same rates that the Company would charge for service, unless the Commission authorizes alternative procedures.

A Customer's wiring will not be extended or connected to furnish service to more than one building or place of use through one meter, even though such building, property, or place of use is owned by the Customer. This rule is not applicable where the Customer's business consists of one or more adjacent buildings or places of use located on the same Premises or operated as an integral unit, under the same name and carrying on parts of the same business.

7~~8~~. Rights of Way. The Customer shall, without cost to the Company, grant the Company a right of way for the Company's lines and apparatus across and upon the property owned or controlled by the Customer, necessary or incidental to the supplying of Electric Service and shall permit access thereto by the Company's employees at all reasonable hours.

~~RULE C~~
~~SERVICE AND LIMITATIONS (Continued)~~

~~Idaho Power Company~~
~~Uniform Service Agreement~~

~~Account No. ______________________~~

~~THIS AGREEMENT Made this ________________ day of ______________________, 20_____ between ____, whose billing address is ________________________ hereinafter, called Customer and IDAHO POWER COMPANY, a corporation with its principal office located at 1221 West Idaho Street, Boise, Idaho, hereinafter called Company.~~

~~NOW THEREFORE, The parties agree:~~

~~1. Idaho Power agrees to supply ______________ volt, three phase Electric Service up to the amount of _________________kilowatts per months pursuant to the Company's Tariff as approved or subsequently amended by the Oregon Public Utility Commission for the Customer's ____ facilities located at or near ____, County of ________________________, State of Oregon.~~

~~2. The availability of power in excess of the amount stated in Paragraph 1 above is not guaranteed and its taking by the Customer may result in a complete or partial curtailment of service to the Customer. The Company has the right to install, at the Customer's expense, any device necessary to protect the Company's system from damage that may be caused by the taking of power in excess of that stated in Paragraph 1. The Customer shall be responsible for any damages to the Customer's system or damages to third parties resulting from the Customer's taking of power in excess of that stated in Paragraph 1.~~

~~3. The term of this Agreement shall be the period during which the Customer is continuously receiving service from the Company under a standard Tariff Schedule or until 30 days following written notification from the Customer to the Company of the Customer's intent to terminate the Agreement or until 60 days following written notification from the Company to the Customer that one of the following conditions exists:~~

~~a. The Customer's greatest monthly metered Demand during the most current twelve consecutive Billing Periods is less than 80 percent of the kilowatts stated in Paragraph 1, or~~

~~b. The Customer's metered Demand during each of the most current twelve consecutive Billing Periods has not equaled or exceeded 1,000 kW, or~~

~~c. The Customer's metered Demand during any Billing Period exceeds the kilowatts stated in Paragraph 1.~~

~~4. Customers whose load requirements are changing or whose Uniform Service Agreement with the Company has been terminated due to any condition, may request the Company enter into a new Uniform Service Agreement with the Customers.~~

~~5. This Agreement and the rates, terms, and conditions of service set forth or incorporated herein, and the respective rights and obligations of the parties here under, shall be subject to valid laws and to the regulatory authority and orders, rules, and regulations of the Oregon Public Utility Commission and such other administrative bodies having jurisdiction. Nothing herein shall be construed as limiting the Oregon Public Utility Commission from changing any terms, rates, charges, classification of service, or any rules, regulations or~~

~~conditions relating to service under this Agreement, or construed as affecting the right of the Company or the Customer to unilaterally make application to the Commission for any such change.~~

~~RULE C~~
~~SERVICE AND LIMITATIONS (Continued)~~

~~6. In any action at law or equity commenced under this Agreement and upon which judgment is rendered the prevailing party, as part of such judgment, shall be entitled to recover all costs, including reasonable attorneys fees, incurred on account of such action.~~

~~This Uniform Service Agreement replaces and supersedes the Uniform Service Agreement between the parties dated the _____________ day of ____________________, 20_____.~~

~~Date ____, 20_____.~~

~~(Appropriate Signatures)~~

Idaho Power/1203
Witness: Michael J. Youngblood

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Michael J. Youngblood
Rule D

July 31, 2009

RULE D
METERING

1. Meter Installations. The Company will install and maintain the metering equipment required by the Company to measure power and energy supplied to the Customer. Meter installations will be done at the Company's expense except as specified below or otherwise specified in a schedule. Customer provisions for meter installations will be made in conformance with Company specifications, the National Electrical Code, and/or applicable state or municipal requirements.

a. Instrument Transformer Metering. ~~If the~~ When instrument transformer metering is requested by the Customer ~~specifically requests instrument transformer metering which is~~ but not required by the Company~~,~~, at the time of the initial meter installation, the Customer will be required to pay the cost of such metering equipment and its installation ~~will be paid to the Company by the Customer~~ in accordance with the charges specified in Schedule 66. When a Customer requests instrument transformer metering not required by the Company at a time other than at the time of the initial meter installation, the actual costs will apply.

b. Off-Site Meter Reading Service. Customers taking single-phase service under Schedule 1 or Schedule 7 may request the Company install metering equipment which provides for off-site meter reading. The installation fee and monthly charges for off-site meter reading capability, when the service is requested by the Customer but not deemed to be cost-effective by the Company, are specified in Schedule 66. The Company shall have the sole right to determine whether an installation is cost-effective. Customers who request the Company-installed off-site meter reading equipment be removed within 90 days of initial installation will be assessed a removal fee in accordance with the provisions of Schedule 66. Due to the specialized nature of the metering equipment, a delay may occur between the time a Customer requests the Off-Site Meter Reading Service and the time the equipment is available for installation. Customers utilizing the Off-Site Meter Reading Service may be required to periodically permit Company personnel access to the meter in order for maintenance to be performed.

c. Load Profile Metering. The Company will install, at the Customer's request, the metering equipment necessary to provide load profile information. The installation fee and monthly charges for load profile capability, when the service is requested by the Customer but not provided by the Company as part of the standard meter installation, are specified in Schedule 66. The options available under the Load Profile Metering Service include Meter Pulse Output Service and Load Profile Recording Service. Customers requesting the Load Profile Recording Service are responsible for providing, at their own expense, a hard-wired phone line to each metering point. Customers who request the Load Profile Metering Service be discontinued within 36 months of initial installation will be assessed a removal fee in accordance with the provisions of Schedule 66.

d. Surge Protection Device Services. At the Customer's request, the following services are available for watt-hour metered Customers only.

i. Installation or Removal. The Company will install or remove, at the Customer's request, a surge protection device supplied by the Customer on the meter base and other utility peripherals to accommodate whole-house surge protection. A Surge Protection Device Installation or Removal Charge will be assessed as specified in Schedule 66.

The Company will not install any surge protection device without proof that the vendor of the surge protection device has executed and delivered to the Company an agreement (in a form acceptable to the Company) which provides for the full defense and indemnification of the Company by the vendor against any claims, suits, or losses associated with such device.

RULE D
METERING
(Continued)

d. Surge Protection Device Services (Continued)

Any surge protection device the Company is requested to install on the meter must be Underwriters' Laboratories, Inc. certified and meet National Electric Energy Testing, Research and Application Centers (NEETRAC) test standards or comparable test standards.

ii. Surge Protection Device Customer Visit Charge.

(1) If a surge protection device installation visit results in the inability of Company personnel to install the surge protection device due to safety concerns, inaccessibility to the meter base or other utility access points, or other factors deemed reasonable by the Company, a Surge Protection Device Customer Visit Charge will be applied as specified in Schedule 66. The Company has the sole right to ultimately determine installation feasibility.

(2) Customers who request the Company perform an on-site visit to assess alleged electrical problems believed to be associated with the surge protection product will be charged a Surge Protection Device Customer Visit Charge as specified in Schedule 66 if no problems associated with the electrical service are found as a result of the visit.

e. Primary Voltage Metering. The Company will install, at its own expense, a maximum of one primary voltage meter at a single Premises to record usage taken at 12.5 kV or 34.5 kV.

2. Measurement of Energy. Except as otherwise specifically provided, all energy delivered by the Company will be billed according to measurement by meters located at or near the Point of Delivery.

If the Company is unable to read a Customer's meter because of reasons beyond the Company's control, such as weather conditions or the inability to obtain access to the Customer's Premises, the Company may estimate the meter reading for the Billing Period on the basis of the Customer's previous use, season of the year and use by similar Customer's of the same class in that service area. Bills rendered on estimated readings will be so designated on the bill. The amount of such estimated bill will be subsequently adjusted, as necessary, when the next actual reading is obtained.

Should the Company be unable to read a Customer's meter for two consecutive Billing Periods, the Company will diligently attempt to contact the Customer by telephone and/or letter, to apprise the Customer of the necessity of a meter reading and to make arrangements to read the meter or request the Customer to record and return the meter reading on a card provided by the Company. If such arrangements cannot be made or if the Customer fails to return the meter reading card, the Company may estimate the meter reading.

3. Failure to Register. If the Company's meters fail to register at any time, the service delivered and energy consumed during such period of failure will be determined by the Company on the basis of the best available data. If any appliance or wiring connection, or any other device, is found on the Customer's Premises which prevents the meters from accurately recording the total amount of energy used on the Premises, the Company may at once remove any such wiring connection or appliance, or device, at the Customer's expense, and will estimate the amount of energy so consumed and not registered as accurately as it is able so to do, and the Customer will pay for any such energy within 5 days after being billed, in accordance with such estimate.

RULE D
METERING
(Continued)

4. Meter Tests. The Company will test and inspect its meters from time to time and maintain their accuracy of registration in accordance with generally accepted practices and with OAR 860-023-0015. The Company will, without charge, test the accuracy of registration of a meter upon request of a Customer, provided that the Customer does not request such a test more frequently than once in a 12-month period. If more than one requested test is performed within a 12-month period, the Customer will be required to pay in advance the estimated cost of a special meter test as specified in Schedule 66. The Company will refund the amount paid by the Customer for the test if the results of the test show the average registration error of the meter exceeds ± 2 percent.

5. Transformer Losses. When delivery of service is on the primary side of the Customer's transformers, the Company may install its meters on the secondary side of the transformers, and, unless otherwise provided in the schedule, in determining the monthly consumption of power and energy, transformer losses and other losses occurring between the Point of Delivery and the meters will be computed and added to the reading of such meters.

6. Meter Reading. Meters will be read to the last kWh registered, normally at intervals of approximately 30 days. In no case will the meter reading interval exceed 45 days.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Michael J. Youngblood
Rule F

July 31, 2009

RULE F
SERVICE ~~CONNECTION~~ ESTABLISHMENT AND DISCONTINUANCE

1. Service Establishment. A Service Establishment Charge as specified in Schedule 66, unless otherwise specified in a different schedule, will be assessed upon initiating metered service with the Company if service at the Point of Delivery is currently energized. The applicable charge will be billed with the first regular bill.

   a. Owners or managers of rental property that arrange with the Company to provide continuous service between tenants will not be assessed a Service Establishment Charge when the service reverts to the responsible party as arranged.

~~2. Continuous Service. At the request of owners or managers of rental property, the Company will provide continuous service between tenant occupancy. Effective August 1, 2006 a Continuous Service Reversion Charge, as specified in Schedule 66, will be assessed each time the service reverts to the responsible party as arranged.~~

3. Service Connection. Where service at the specified Point of Delivery is currently disconnected from the Company's system, a Service Connection Charge as specified in Schedule 66 will be assessed at the time service is connected. The Service Connection Charge applies to all service connections for both metered and unmetered service and will be billed with the first regular bill. The Service Establishment Charge does not apply when service is reconnected.

4~~2~~. Service Discontinuance. At the Customer's request, the Company will disconnect service during normal working hours. There is no charge for discontinuing service.

   a. When a Customer requests service be discontinued, service will not be disconnected if another party has agreed to accept responsibility for service at the Point of Delivery. Upon initiating service, the Customer requesting service will be billed a Service Establishment Charge in accordance with this rule.

5~~3~~. Termination Practices. The Company's practices relating to Termination of Service are governed by the Oregon Administrative Rules (OAR) of the Oregon Public Utility Commission, in effect at the time the event occurred which required application of the OAR. If the Company's Rules and Regulations on file with the Oregon Public Utility Commission contain provisions which conflict with the OAR, the provisions of the OAR supersede those included in the Company's Rules and Regulations.

6~~4~~. Field Visit. ~~The Company may assess the Customer the~~ A Field Visit Charge, as specified ~~shown on Schedule~~ in Schedule 66, ~~whenever the~~ will be assessed when a Company representative visits a service (C) address intending to ~~reconnect or~~ disconnect or connect service, but due to ~~the~~ Customer~~'s~~ action, the Company representative is unable to complete the ~~reconnection or~~ disconnection or connection at the time of the visit. ~~If a payment is collected at the service address, the Company employee accepting payment will not dispense change for payment tendered in excess of the amount due or owing. Any excess payment shall be credited to the Customer's account.~~

7~~5~~. Unauthorized Reconnection. Where damage to the Company's facilities has occurred due to tampering or where reconnection of service has been made by other than the Company, an Unauthorized Reconnection Charge may be collected as specified in Schedule 66. This charge is not a waiver by the Company of the rights to recover losses due to tampering. In addition to the above-mentioned charge, the customer receiving service shall be liable for any damage to Company property.

Idaho Power/1205
Witness: Michael J. Youngblood

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Michael J. Youngblood
Rule G

July 31, 2009

RULE G
BILLINGS

1. Fractional Periods. When the Customer's Billing Period is less than 27 days or greater than 36 days, the Energy Charge for ~~Upon initiating or discontinuing~~ service under Schedules 1, 7, 9, 19, or 24 the Energy Charge will be calculated using actual meter readings. The Energy Charge for services provided under Schedule 40 will be determined using the daily kWh calculated on the basis of load size and number of units served multiplied by the actual number of days since the account was opened or since the previous billing, where appropriate. The proration of the applicable Demand Charge, Basic Charge, Facilities Charge, and Service Charge specified in the appropriate schedule will be calculated by dividing the charge by 30 and multiplying the result by the actual number of days since the account was opened or since the previous meter reading, where appropriate. However, the prorated Service Charge for Schedules 1, 7, 9, 19, or 24 or the Minimum Charge for Schedule 40, will be no less than the amount specified in Schedule 66. For Schedule 15, the proration of the applicable Monthly Charge will be calculated by dividing the charge by 30 and multiplying the result by the actual number of days since the account was opened or the previous billing, where appropriate; however, in no event will the charge be less than the Fractional Period Minimum Billings amount specified in Schedule 66.

2. Corrected Billings. Whenever it is determined that a Customer was billed under an inappropriate schedule, the Customer will be rebilled under the appropriate schedule, except if the Company selected the schedule on the basis of available information and acted in good faith, the Company will not be required to rebill or adjust billings. The rebilling period will be no more than the 3-year period as provided by OAR 860-021-0135.

If the average error for any meter test exceeds ±2 percent, corrected billings will be prepared. The corrected billings will not exceed 6 months if the time when the malfunction or error began is unknown. If the time when the malfunction or error began is known, the corrected billings will be from that time, but will not exceed the 3 year period as provided by OAR 860-021-0135. The Company shall provide written notice to the Customer detailing the circumstances, time period, and adjustment amount of an over or underbilling. If an underbilling occurs, the Company will offer and enter into reasonable payment arrangements with the Customer. The Customer shall be notified in writing of the opportunity for time payments and of the Commission's dispute resolution process. For any overbillings, the Customer will have the choice of a refund or a credit on future bills.

3. Due Dates. The Company's practices relating to Due Dates are governed by the Oregon Administrative Rules (OAR) of the Oregon Public Utility Commission, in effect at the time the event occurred which required application of the OAR. If the Company's Rules and Regulations on file with the Oregon Public Utility Commission contain provisions which conflict with the OAR, the provisions of the OAR supersede those included in the Company's Rules and Regulations.

4. Returned Checks. Checks or payments remitted by Customers in payment of bills are accepted conditionally. A Returned Check Charge, as specified in Schedule 66, will be assessed the Customer for handling each check or payment upon which payment has been refused by the bank.

5. Temporary Suspension of Demand. When the Customer is obliged temporarily to suspend operation due to strikes, action of any governmental authority, acts of God or the public enemy, the Customer may procure a proration of the monthly Billing Demand based upon the period of such suspension by giving immediate written notice to the Company. However, all monthly Minimum Charges and/or obligations will continue to apply as specified in the applicable schedule or a written agreement.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Michael J. Youngblood
Rule K

July 31, 2009

RULE K
CUSTOMER'S LOAD AND OPERATIONS

1. Interference with Service. The Company reserves the right to refuse to supply loads of a character that may seriously impair service to any other Customers, or may disconnect existing service if it is seriously impairing service to any other Customers. In the case of pump hoist or elevator motors, welders, furnaces, compressors, and other installations of like character where the use of electricity is intermittent, subject to ~~violent~~ voltage fluctuations, ~~or causes~~ voltage notching or draws a nonsinusoidal (harmonically distorted) load current, the Company may require the Customer to provide equipment, at the Customer's expense, to reasonably limit such fluctuations.

2. Practices and Requirements of Harmonic Control. Customers are required to comply with the *Practices and Requirements of Harmonic Control in Electric Power Systems* as set forth in the current Institute of Electrical and Electronic Engineers (IEEE) Standard 519~~-1992~~. The values indicated by IEEE Standard 519~~-1992~~ apply at the point where the Company's equipment interfaces with the Customer's equipment.

3. Change of Load Characteristic. The Customer shall give the Company prior notice before making any significant change in either the amount or electrical character of the Customer's electrical load thereby allowing the Company to determine if any changes are needed in the Company's equipment or distribution system. The Customer may be held liable for damages to the Company's equipment resulting from the Customer's failure to provide said notice of change in electrical load.

4. Protection of Electrical Equipment. ~~The Company reserves the right to refuse single phase service to motors larger than 7 ½ horsepower.~~

The Customer is solely responsible for the selection, installation, and maintenance of all electrical equipment and wiring (other than the Company's meters and apparatus) on the load side of the Point of Delivery. The Customer should provide adequate protection for equipment, data, operations, work and property under the Customer's control from system disturbances such as (a) high and low voltage, (b) surges, harmonics, and transients in voltage, and (c) overcurrent. For unidirectional and three-phase equipment, the Customer should provide adequate protection from "single phasing conditions", reversal of phase rotation, and phase unbalance.~~All motor installations should include effective protection apparatus or have inherent construction within the motor to accomplish equivalent protection as follows:~~

5. Motor Installations. The Company reserves the right to refuse single phase service to motors larger than 7 ½ horsepower.

a. Motor Connection. All motor installations greater than 7 ½ horsepower (HP) must be approved by the Company to determine how the motor's connection will affect the Company's system. Changes to Company facilities necessary to address the effects of, but not limited to, flicker, voltage balance, voltage level, or reactive power may be at the Customer's expense.~~a. Overload or overcurrent protection for each motor by suitable thermal relays, fuses or circuit interrupting devices automatically controlled to disconnect the motor from the line to protect it from damage caused by over-heating. Installation or protection in each conductor connected to three-phase motors is recommended.~~

~~b. Open phase protection on all polyphase installations to disconnect motors from the line in the event of opening of one phase.~~

~~c. All polyphase motors for the operation of passenger and freight elevators, cranes, hoists, draglines, and similar equipment will be provided with reverse phase relays or equivalent devices, for protection in case of phase reversal.~~

~~d. Motors that cannot safely be subjected to full voltage at starting should be provided with a device to insure that, on failure of voltage such motors will be disconnected from the line. It is also recommended that such device be provided with a suitable time delay relay.~~

RULE K
CUSTOMER'S LOAD AND OPERATIONS
(Continuous)

5. Motor Installations (Continued)

b. ~~5.~~ Allowable Motor Starting Currents. The starting currents (~~such currents shall be~~ as determined by tests or based on published data by manufacturers) of alternating current motors ~~up to 100 horsepower~~ will not exceed the allowable locked rotor current values shown in the following table, corrections being allowed to compensate for the difference between the voltage supply at the motor terminals and its rated voltage. If the starting current of the motor exceeds the locked rotor current value ~~given in~~ indicated by the table below, a starter must be used or other means employed to limit the starting current to the locked rotor current value specified, except that such starting equipment may be omitted by written permission of the Company where the absence of such starting equipment will not cause objectionable voltages ~~fluctuations~~. Maximum permissible locked rotor current values in the following table apply~~ies~~ to a single motor installation. Starters may be omitted on the smaller motors of an installation consisting of more than one motor when their omission will not result in a current in excess of the allowable locked rotor current of the single largest motor of the group.

	~~Allowable Locked Rotor Currents~~			
	~~Single~~	~~Polyphase Motors~~		
	~~Phase~~	~~240 Volt~~	~~480 Volt~~	~~2,400 Volt~~
~~Rated Size~~	~~240 Volt~~	~~3-phase~~	~~3-phase~~	~~3-phase~~
~~7 1/2 HP~~	~~110 amp~~			
~~10 HP~~	~~147 amp~~	~~141 amp~~	~~71 amp~~	
~~15 HP~~		~~197 amp~~	~~99 amp~~	
~~20 HP~~		~~250 amp~~	~~125 amp~~	
~~25 HP~~		~~304 amp~~	~~152 amp~~	
~~30 HP~~		~~360 amp~~	~~180 amp~~	
~~40 HP~~		~~380 amp~~	~~190 amp~~	
~~50 HP~~		~~400 amp~~	~~200 amp~~	~~40 amp~~
~~60 HP~~		~~480 amp~~	~~240 amp~~	~~48 amp~~
~~75 HP~~		~~600 amp~~	~~300 amp~~	~~60 amp~~
~~100 HP and Over~~		~~Consult Company~~		

Allowable Locked Rotor Currents*						
	Single Phase Motors		Three Phase Motors			
	208 Volt	240 Volt	208 Volt	240 Volt	480 Volt	Over 480 Volt
Rated Size HP	Starting Amps Allowed					
7.5	127	110				
10			163	141	71	
15			227	197	99	
20			288	250	125	
25			351	304	152	
30			415	360	180	
40			438	380	190	
50			462	400	200	
60			554	480	240	
75			692	600	300	
Over 75						

*Note: If no value is shown, Company approval of the locked rotor current is required prior to motor installation.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Michael J. Youngblood
Rule L

July 31, 2009

RULE L
Deposits

1. Residential Customers. The Company may require a deposit from a residential customer if: (1) the Customer is unable to establish credit as defined in section 1 of OAR 860-021-0200, (2) the Customer has received electric service from either the Company or another Oregon regulated electric utility within the preceding 24 months and at the time service was terminated owed an account balance that was not paid according to its terms for which a dispute was not registered within 60 days of the date service was terminated, or (3~~2~~) was previously terminated for theft of service by the Company or any Oregon regulated utility or was otherwise found to have diverted utility service. In either of these two cases, the Company may require a deposit from the Customer equal to one-sixth of the estimated annual billing at the rates then in effect if the calculated deposit amount exceeds $250. The Company's practices relating to deposit payment arrangements for residential customers are governed by OAR 860-021-0205.

2. Commercial and Special Contract Customers (Schedules 7, 9, 19 and Special Contract). The Company may require a deposit from Commercial or Special Contract customers if: (1) the Customer has been disconnected for nonpayment within the last 12 months; (2) the Customer has received more that two 15-day termination notices within the last 12 months; (3) the Customer becomes a debtor in a bankruptcy proceeding; (4) the Customer falsifies information in the application for service; (5) the Customer fails to establish credit satisfactory to the Company; (6) the nature of the Customer's business is speculative or subject to a high rate of failure; (7) the Customer is applying for service with the Company for the first time; (8) the Customer has an outstanding prior service account with the Company that accrued within the last four years and at the time of application for service remains unpaid and not in dispute; or (9) the risk of future loss is evident based on the Customer's current commercial credit rating; or (10) the Customer requests service be provided for a period of less than 90 days. If any of the criteria (1) through (9) are met, the Company may require a deposit not exceeding two times the Customer's estimated monthly billing at the service address if the calculated deposit amount exceeds $250. When a Customer requests service be provided for less than 90 days, a deposit equal to $100 or twice the estimated monthly billing, whichever is greater, may be required.

A new Customer can establish satisfactory credit by presenting to the Company one of the following: (1) a statement from another electric utility showing the Customer's most recent 12-month credit history during which time the Customer had not received any notices of disconnection; (2) a letter of credit from a major financial institution; or (3) a current Dun and Bradstreet report that substantiates the credit reliability of the Customer. Deposits may be paid in two equal installments; the first installment must be paid at the time of the application for service or upon notice from the Company to existing customers, and the second installment must be paid within 30 days.

3. Written Explanation for Denial of Service or Requirement of Deposit. If the Company denies service or requires a cash deposit as a condition of providing or continuing service, then it will provide a written explanation to the Customer stating the reasons why it denies service or requires a deposit. The applicant or Customer will be given an opportunity to rebut those reasons.

4. Interest on Deposits. Interest on deposits held by the Company shall be accrued at the rate established by the Commission specified in OAR 860-021-0210. Interest shall be computed from the time the deposit is made until it is refunded or applied to the Customer's regular bill. Interest will not accrue on a deposit if service is discontinued temporarily at the request of a Customer who leaves the deposit with the Company for future use as a deposit, or if service has been permanently discontinued and the Company has been unsuccessful in its attempt to refund a deposit.

5. Refund of Deposit. Deposits will be refunded with interest or applied to the next monthly bill (at the Customer's option) if the Customer's account is current and the account has not been disconnected for nonpayment nor been issued more than two 5-day disconnection notices during the previous 12 months.

RULE L
Deposits
(Continued)

6. Retention During Dispute. The Company may retain the deposit pending the resolution of a dispute over termination of service. If the deposit is later returned to the Customer, the Company shall pay interest at the annual rates established in OAR 860-021-0210 for the entire period over which the deposit was held.

7. Transfer of Deposit. Deposits shall not be transferred from one Customer to another Customer or between classes of service, except at the Customer's request. When a Customer with a deposit on file transfers service to a new location within the Company's service area, the deposit shall remain with the Customer at the new location.

Idaho Power/1208
Witness: Michael J. Youngblood

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Michael J. Youngblood
Schedule 61

July 31, 2009

SCHEDULE 61
POWER QUALITY PROGRAM

AVAILABILITY

Service under this Schedule is available to Customers throughout the Company's service area within the State of Oregon.

PROGRAM DESCRIPTION

The Power Quality Program is intended to provide Customers with a mechanism to identify and correct electrical problems within the Customer's residence or business which impact the Customer's power quality.

SERVICES PROVIDED

The Company will provide the following services:

Technical Assistance: The Company will perform a symptomatic audit of the Customer's residence or business to assist the Customer in identifying the probable cause of any power quality problems and possible solutions to any power quality problems identified. Technical Assistance is provided at no charge to the Customer.

Home Wiring Audit: A $~~25~~ 40 payment is provided by the Company to residential Customers who have a home wiring audit ~~for power quality~~ performed by a licensed electrician participating ~~in the Company's Power Quality Program~~. To have a home wiring audit performed, a Customer is responsible for contacting the Company to request the Home Wiring Audit form and then ~~can~~ contacting a licensed electrician to perform the audit. ~~the Company or an electrician participating in the Power Quality Program. Customers contacting the Company will be given a list of electricians participating in the Power Quality Program.~~ The Customer is also responsible for ~~selecting~~ ensuring the electrician ~~to~~ performs the audit per the instructions of the Home Wiring Audit form. The charge for the audit will be established by the electrician and will be billed by the electrician directly to the Customer. The Customer is responsible for paying the electrician the charge for performing the audit.

The $~~25~~40 payment is provided to the Customer upon receipt by the Company of the appropriate copy of the completed Home Wiring Audit form. The Customer is responsible for submitting the Home Wiring Audit form to the Company.

Purpose of Payment: The purpose of the $40 payment is to assist the Customer in identifying any wiring deficiencies that may be causing power usage problems. The payment is not an indication that the Company has performed any analysis as to the safety of the Customer's wiring or that the Company concurs with the findings of the electrician's wiring audit.

~~Financing: Financing through the Company is offered for the purchase of equipment or repairs to correct power quality problems. The equipment and repairs eligible for financing under the Power Quality Program include transient surge protectors, power conditioning equipment, uninterruptible power supplies, grounding repairs, service entrance repairs and upgrades, and wiring and outlet repairs.~~

~~Financing is available at the fixed rate of interest in effect for the Power Quality Program at the time the loan is made. The fixed rate is adjusted on January 1, May 1, and September 1 of each year. Repayment of the loan is collected through the Customer's monthly billing. Two loan categories are available: $25 to $400 and $401 to $10,000. The financing arrangements for each category are:~~

~~1. $25 through $400: The minimum monthly payment is $10. The interest rate is set equal to the prime rate of interest in effect on the first business day of the month immediately preceding the adjustment month.~~

~~2. $401 through $10,000: The minimum monthly payment is $15. The interest rate is set equal to the prime rate of interest in effect on the first business day of the month immediately preceding the adjustment month plus three percent. Customer taking loans of less than $10,000 must repay the loan amount within 30 months. For all other loan amounts, residential Customers can make monthly payments over 30, 60, 90, or 120 months; commercial Customers can make monthly payments over 30 or 60 months.~~

Idaho Power/1209
Witness: Michael J. Youngblood

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Michael J. Youngblood
Schedule 62

July 31, 2009

SCHEDULE 62
GREEN ENERGY PURCHASE
PROGRAM RIDER
(OPTIONAL)

PURPOSE

The Green Energy Purchase Program is an optional, voluntary program designed to provide customers an opportunity to participate in the purchase of new environmentally friendly "green" energy. Funds collected in this program will be wholly distributed to the purchase of Green Energy Products.

APPLICABILITY

Service under this schedule is applicable to all Customers~~s~~ and non-customers who choose to participate in this Program.

MONTHLY GREEN ENERGY PURCHASE CONTRIBUTION

Customers designate their level of participation by choosing a fixed dollar per month amount. The monthly Green Energy Purchase Program contribution is in addition to all other charges included in the service schedule under which the Customer receives electrical service and will be added to the Customer's monthly electric bill. Non-Customer participants will be issued a monthly invoice that reflects their designated fixed dollar per month contribution.

The Program funds will wholly be used to purchase green energy or to cover the green energy price premium. The Company will acquire Green Energy Products within one year of the Customer's purchase under this Schedule.

GREEN ENERGY PRODUCTS

For purposes of this Program, green energy products include but are not limited to the following:

Green Tags. Green tags consist of the Non-Power Attributes resulting from the generation of energy by a qualified renewable resource. Such attributes may be fuel, emissions, or other environmental characteristics deemed of value by a green tag buyer. The price of Green Tags may include administration costs of the Green Tag broker.

Non-Power Attributes include but are not limited to any avoided emissions of pollutants to the air, soil or water such as sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO) and any other pollutant that is now or may in the future be regulated under the pollution control laws of the United States; and further include any avoided emissions of carbon dioxide (CO_2), methane (CH_4) and any other greenhouse gas (GHG) that contributes to the actual or potential threat of altering the Earth's climate. Non-Power Attributes are expressed in MWh.

Non-Power Attributes do not include any energy, capacity, reliability or other power attributes used to provide electricity services.

PROGRAM CONSIDERATIONS

No electric service disconnections will result in the event of non-payment of Program commitments.

Idaho Power/1210
Witness: Michael J. Youngblood

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Michael J. Youngblood
Schedule 66

July 31, 2009

SCHEDULE 66
MISCELLANEOUS CHARGES

PURPOSE

The purpose of this schedule is to accumulate all miscellaneous charges that are included in the Company's Rules, Regulations, and Rates.

APPLICABILITY

This schedule applies to all Customers taking service under the Company's Oregon Tariff except as expressly limited by a Rule or a Schedule.

CHARGES

RULE D ~~CHARGE~~

1. Instrument Transformer Metering

Current Transformer

Single Phase

120/240 Volt	$214.00
240/480 Volt	$247.00
120/208 Volt Network	$275.00

Polyphase

120/240 Volt Delta	$437.00
240/480 Volt Delta	$438.00
120/208 Volt Wye	$467.00
277/480 Volt Wye	$471.00

Voltage Transformer (secondary voltages only)
~~(secondary voltages only)~~Additional cost per voltage transformer $160.00

Primary Metering ~~Actual Cost~~
Work Order costs are applicable.

2. Off-Site Meter Reading Service

Single-Phase, Non-Demand Metering

Class 200 R300 Register (standard metering)	$ 3.65 per month
Class 320 R300 Register (standard metering)	$ 4.40 per month
Class 10 R 300 Register (instrument transformer metering)	$ 4.40 per month
Installation Fee (payable with first monthly payment)	$ 25.00
Removal Fee (if removed within 90 days of installation)	$ 25.00

SCHEDULE 66
MISCELLANEOUS CHARGES
(Continued)

RULE D (Continued)

3. Load Profile Metering

Pulse Output Service

With an existing Electronic Demand Meter	$ 5.00 per month
Without an existing Electronic Demand Meter	$ 13.00 per month
Installation Fee (payable with first monthly payment)	$ 70.00
Removal Fee (if removed within 90 days of installation)	$ 60.00

Load Profile Recording Service

With an existing Electronic Demand Meter	$ 17.50 per month
Without an existing Electronic Demand Meter	$ 25.50 per month
Installation Fee (payable with first monthly payment)	$ 80.00
Removal Fee (if removed within 90 days of installation)	$ 60.00

4. Special Meter Test

Non-Residential	Actual Labor & Mileage Rates
Residential	Not to Exceed $30.00

5. Surge Protection Device Services

Surge Protection Device Installation or Removal Charge	$ 43.00
Surge Protection Device Customer Visit Charge	$ 25.00

RULE F (all times are stated in Mountain Time)

6. Service Establishment Charge $ 20.00

7. Continuous Service Reversion Charge $ 10.00

8. Field Visit Charge $ 20.00

9. Service Connection Charge

Schedules 1, 7, 9

Monday through Friday

7:30 am to 6:00 pm	$ 20.00
6:01 pm to 9:00 pm	$ 45.00
9:01 pm to 7:29 am	$ 80.00

Company Holidays and Weekends

7:30 am to 9:00 pm	$ 45.00
9:01 pm to 7:29 am	$ 80.00

SCHEDULE 66
MISCELLANEOUS CHARGES
(Continued)

RULE F (all times are stated in Mountain Time) (Continued)

9. Service Connection Charge (Continued)

Schedules 15, 19, 24, 40, 41, 42

Monday through Friday

7:30 am to 6:00 pm	$ 40.00
6:01 pm to 9:00 pm	$ 65.00
9:01 pm to 7:29 am	$100.00

Company Holidays and Weekends

7:30 am to 9:00 pm	$ 65.00
9:01 pm to 7:29 am	$100.00

~~Regular Business Hours [(1)]~~

~~Schedules 1, 7, 9~~	~~$ 20.00~~
~~Schedules 15, 19, 24, 40, 41, 42~~	~~$ 40.00~~

~~Non Regular Business Hours~~

~~Tier 1 [(2)]~~

~~Schedules 1, 7, 9~~	~~$ 45.00~~
~~Schedules 15, 19, 24, 40, 41, 42~~	~~$ 65.00~~

~~Tier 2 [(3)]~~

~~Schedules 1, 7, 9~~	~~$ 80.00~~
~~Schedules 15, 19, 24, 40, 41, 42~~	~~$100.00~~

~~(1) Customer request between 7:30 a.m. to 6:00 p.m., Monday-Friday, except Company recognized holidays.~~

~~(2) Customer request between 6:01 p.m. to 9:00 p.m., Monday-Friday. Company recognized holidays and weekends between 7:30 a.m. to 9:00 p.m.~~

~~(3) Customer request for between 9:01 p.m. to 7:29 a.m., Monday-Friday. Company recognized holidays and weekends between 9:01 p.m. to 7:29 a.m.~~

10. Unauthorized Reconnection Charge $ 50.00

RULE G

11. Returned Check Charge $ 20.00

12. Fractional Period Minimum Billings

Schedules 1 and 7	$ 3.00
Schedules 9 and 19 Secondary	$ 5.00
Schedules 9 and 19 Primary & Transmission	$ 10.00
Schedule 24	$ 3.00
Schedule 15	$ 3.00
Schedule 40	$ 1.50

RULE H

13. Temporary Service Return Trip Charge $ 35.00

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Michael J. Youngblood
Schedule 90

July 31, 2009

SCHEDULE 90
DIRECT ACCESS PILOT PROGRAM
ENERGY SERVICE

AVAILABILITY

Service under this schedule is available in all territory in the State of Oregon outside the Company's allocated Oregon service territory where direct access pilot programs are in effect.

APPLICABILITY

Service under this schedule applies to customers who have viable alternatives to incumbent utility service under direct access pilot programs to purchase energy services from an electric energy service supplier for delivery to the system of the customer's electric delivery provider.

SPECIAL TERMS AND CONDITIONS

This tariff shall incorporate by reference any codes of conduct or terms and conditions approved by the Commission relating to electric energy service supplier participation in direct access pilot programs including, but not limited to, all cost reporting and accounting requirements for public utility electric energy service suppliers.

PRICES

Pricing under this tariff shall be market-based. The Company shall price in a manner that will not violate state or federal antitrust laws.

The Company shall price its services:

a. to cover at least the relevant costs during the term of service, and

b. to assure that just and reasonable rates are established for the Company's Customers in its allocated Oregon service territory.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Michael J. Youngblood
Calculation of Revenue Impact – Summary

July 31, 2009

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
General Rate Case
Filed July 31, 2009

Summary

Line No	Tariff Description	Rate Sch. No.	Average Number of Customers (1)	Normalized Energy (kWh) (1)	8/8/2005 Base Revenue	Adjusted Base Revenue (2)	Proposed Class Increase	Proposed Base Revenue	Percent Change Over Adj. Base Revenue
	Uniform Tariff Rates:								
1	Residential Service	1	13,415	198,558,922	$9,779,141	$11,262,377	$4,205,518	$15,467,895	37.34%
2	Small General Service	7	2,999	17,201,052	$1,047,646	$1,176,138	$484,093	1,660,231	41.16%
3	Large General Service	9	1,339	133,134,131	$5,991,606	$6,986,118	$765,834	7,751,952	10.96%
4	Dusk to Dawn Lighting	15	0	424,083	$95,458	$98,625	$0	98,625	0.00%
5	Large Power Service	19	8	268,576,620	$7,949,473	$9,955,740	$587,468	10,543,208	5.90%
6	Agricultural Irrigation Service	24	1,519	60,553,810	$2,393,811	$2,846,148	$1,272,053	4,118,201	44.69%
7	Unmetered General Service	40	3	12,900	$676	$772	$186	958	24.09%
8	Street Lighting	41	13	823,084	$100,831	$106,978	$13,280	120,258	12.41%
9	Traffic Control Lighting	42	6	17,262	665	794	$488	1,282	61.46%
10	***Total Oregon Retail Sales***		**19,303**	**679,301,864**	**27,359,306**	**32,433,690**	**$7,328,920**	**$39,762,610**	**22.60%**

(1) 2009 Forecasted Test Year
(2) 8/8/2005 Base Revenue plus Revenue from APCU 2008 October Update

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
General Rate Case
Filed July 31, 2009

Summary

Line No	Tariff Description	Rate Sch. No.	Average Number of Customers (1)	Normalized Energy (kWh) (1)	8/8/2005 Base Revenue	Adjusted Base Revenue (2)	Proposed Class Increase	Proposed Base Revenue	Percent Change Over Adj. Base Revenue
	Uniform Tariff Rates:								
1	Large General Secondary	9S	1,334	116,956,858	$5,457,664	$6,331,332	$620,525	$6,951,857	9.80%
2	Large General Primary	9P	5	16,177,273	533,942	654,786	145,309	800,095	22.19%
3	Large General Transmission	9T	0	0	0	0	0	0	0.00%
4	Total Schedule 9		1,339	133,134,131	$5,991,606	$6,986,118	$765,834	$7,751,952	10.96%
5	Large Power Secondary	19S	0	0	$0	$0	$0	$0	0.00%
6	Large Power Primary	19P	6	181,464,005	5,356,604	6,712,140	587,469	7,299,609	8.75%
7	Large Power Transmission	19T	2	87,112,615	2,592,869	3,243,600	(1)	3,243,599	(0.00)%
8	Total Schedule 19		8	268,576,620	$7,949,473	$9,955,740	$587,468	$10,543,208	5.90%
9	Irrigation Secondary	24S	1,519	60,553,810	$2,393,811	$2,846,148	$1,272,053	$4,118,201	44.69%
10	Irrigation Transmission	24T	0	0	0	0	0	0	0.00%
11	Total Schedule 24		1,519	60,553,810	$2,393,811	$2,846,148	$1,272,053	$4,118,201	44.69%

(1) 2009 Forecasted Test Year
(2) 8/8/2005 Base Revenue plus Revenue from APCU 2008 October Update

Idaho Power/1213
Witness: Michael J. Youngblood

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Michael J. Youngblood
Proposed Tariff Sheets – Legislative Format

July 31, 2009

OREGON PUBLIC UTILITY COMMISSION

TARIFF NO. E-27

GENERAL RULES, REGULATIONS AND RATES

APPLICABLE TO ELECTRIC SERVICE IN THE TERRITORY

SERVED FROM THE COMPANY'S INTERCONNECTED SYSTEM

IN OREGON

GENERAL RULES AND REGULATIONS INDEX

IDAHO POWER COMPANY

P.U.C. ORE. NO. E-27 ORIGINAL SHEET NO. iii

SCHEDULE INDEX

RULE A
INTRODUCTION

These Rules and Regulations are a part of the Tariff of Idaho Power Company and apply to the Company and every Customer to whom service is supplied; provided, that in case of conflict between these Rules and Regulations and the provisions of any schedule of this Tariff, the provisions of such schedule will govern as to service supplied thereunder.

RULE B
DEFINITIONS

The terms listed below, which are used frequently in this Tariff, will have the stated meanings:

Billing Period is the period intervening between meter readings and shall be approximately 30 days. However, Electric Service covering 27-~~33~~ 36 days inclusive will be considered a normal Billing Period.

Commission refers to the Oregon Public Utility Commission.

Company refers to Idaho Power Company.

Customer is the individual, partnership, association, organization, public or private corporation, government or governmental agency receiving or contracting for Electric Service. Customer status may be retained when a Customer voluntarily disconnects and subsequently requests service from the Company within 20 days as provided by OAR 860-021-0008.

Demand is the average kilowatts (kW) or horsepower (HP) supplied to the Customer during the 15-consecutive-minute period of maximum use during the Billing Period, as shown by the Company's meter, or determined in accordance with the demand clause in the schedule under which service is supplied. In no event, however, will the maximum demand for the Billing Period be less than the demand determined as specified in the schedule.

Electric Service is the availability of power and energy in the form and at the voltage specified in the Oregon Electric Service Application or agreement, irrespective of whether electric energy is actually utilized, measured in kilowatt-hours (kWh).

Month (unless calendar month is stated) is the approximate 30-day period coinciding with the Billing Period.

Normal Business Hours are 8:00 a.m. to 5:00 p.m., Monday through Friday, excluding holidays observed by the Company. Notices of office closures for holidays are posted, in advance, at the Company office entrances.

Point of Delivery is the junction point between the facilities owned by the Company and the facilities owned by the Customer; OR the Point at which the Company's lines first become adjacent to the Customer's property; OR as otherwise specified in the Company's Tariff.

Power Factor is the percentage obtained by dividing the maximum demand recorded in kW by the corresponding kilovolt-ampere (kVA) demand established by the Customer.

Premises is a building, structure, dwelling or residence of the Customer. If the Customer uses several buildings or structures in the operation of a single integrated commercial, industrial, or institutional enterprise, the Company may consider all such buildings or structures that are in proximity to each other to be the Premises, even though intervening ownerships or public thoroughfares exist.

RULE B
DEFINITIONS
(Continued)

Service Level is defined as follows:

Secondary Service is service taken at 480 volts or less, or when the definitions of Primary Service and Transmission Service do not apply. The Company is responsible for providing the transformation of power to the voltage at which it is to be used by the Customer taking Secondary Service.

Primary Service is service taken at 12.5 kilovolts (kV) to 34.5 kV. Customers taking Primary Service are responsible for providing the transformation of power to the voltage at which it is to be used by the Customer.

Transmission Service is service taken at 44 kV or higher. Customers taking Transmission Service are responsible for providing the transformation of power to the voltage at which it is to be used by the Customer.

RULE C
SERVICE AND LIMITATIONS

1. Rates and Tariff. Service supplied by the Company will be in accordance with the Tariff on file with the state regulatory authority having jurisdiction, and as in effect at the time service is supplied. All service rates and agreements are subject to the continuing jurisdiction and regulation of such authority, as provided by law. Those matters relating to customer service not expressly addressed in the Rules, Regulations, and Rates of this Tariff shall conform to the requirements of Oregon Administrative Rules, Chapter 860, Division 21.

When any municipal corporation or other local taxing agency imposes on the Company any franchise, occupation, sales, license, excise, business, operating, privilege, or use of street tax or exaction, the amount thereof which exceeds 3 1/2 percent of the gross revenue (pursuant to OAR 860-22-0040) derived from Electric Service furnished Customers within the levying municipality or taxing district will be billed pro rata to such Customers in accordance with Schedule 95. When Customers are billed as herein provided, the amount will be separately stated on, and added to, the regular billing.

2. Supplying of Service. Service will be supplied under a given schedule only to Points of Delivery as are adjacent to facilities of the Company, adequate and suitable as to capacity and voltage for the service desired and under the schedule applicable thereto. The Company will not be obligated to construct extensions or install additional service facilities except in accordance with Rule H. In all other cases, special agreements between the Customer and the Company may be required.

3. Service Application. The Company will normally accept an application for service from the Customer by telephone, through the Company's Web site or by other oral communication. The Company may however, at its discretion, require the Customer to sign an application requesting service. As provided in OAR 860-021-0055, applications for temporary, seasonal, or short-term service for periods of not less than one month are accepted when the Company has available capacity for the service required and the Customer pays the Company in advance the estimated net cost of installing and removing the facilities required to supply service.

~~4. Service Agreement. Service to all loads equal to or in excess of 1,000 kW Demand at a single Point of Delivery are subject to preapproval by the Company through a written and signed Uniform Service Agreement between the Customer and the Company. The Company cannot guarantee the availability of power equal to or in excess of 1,000 kW to Customers who have not entered into a written Uniform Service Agreement.~~

4~~5~~. Choice of Schedules. The Company's schedules are designed to provide monthly rates for service supplied to the Customer on an annual basis. The Customer may elect to take service under any of the schedules applicable to this annual service requirement, and the Company will endeavor to assist in the selection of the appropriate schedule most favorable to the Customer. Changing of schedules will occur only when the characteristics of the Customer's usage change such that another applicable schedule is deemed more favorable to the Customer when applied to the Customer's annual service requirements. Customers receiving service under Schedules 7, 9, and 19 will be reviewed on a monthly basis under the provisions established in the Applicability section of each of these schedules.

5~~6~~. Point of Delivery Service Requirements. A Customer may be served at more than one Point of Delivery at the same Premises if practicable, unless otherwise specified in a schedule. Service at each Point of Delivery at the same Premises will be offered under the appropriate schedule. The Customer's request for service at an additional Point of Delivery will be subject to the applicable line extension rules of the Company. The Company may refuse to provide service at more than one Point of Delivery at the same Premises if it is determined by the Company that the additional Point of Delivery cannot be provided without jeopardizing the safety and reliability of the Company's system or service to the Customer or to other Customers. Service provided to a Customer at multiple Points of Delivery at the same Premises will not be interconnected electrically.

RULE C
SERVICE AND LIMITATIONS
(Continued)

Point of Delivery Service Requirements (Continued)

Where separate Points of Delivery exist for supplying service to a Customer at a single Premises or separate meters are maintained for measurement of service to a Customer at a single Premises, the meter readings will not be combined or aggregated for any purpose except for determining if the Customer's total power requirement exceeds ~~25~~20,000 kW. Special contract arrangements will be required when a Customer's aggregate power requirement exceeds ~~25~~20,000 kW.

Service delivered at low voltage (600 volts or under) will be supplied from the Company's distribution system to the outside wall of the Customer's building or service pole, unless an exception is granted by the Company and the City or State Electrical Inspector.

The Customer's facilities will be installed and maintained in accordance with the requirements of the National Electrical Code.

6~~7~~. Limitation of Use. A Customer will not resell electricity received from the Company to any person except where the Customer is owner, lessee, or operator of an apartment house, mobile home court, or other multi-family dwelling where the use has been sub-metered prior to January 1, 1974, and the use is billed to residential tenants at the same rates that the Company would charge for service, unless the Commission authorizes alternative procedures.

A Customer's wiring will not be extended or connected to furnish service to more than one building or place of use through one meter, even though such building, property, or place of use is owned by the Customer. This rule is not applicable where the Customer's business consists of one or more adjacent buildings or places of use located on the same Premises or operated as an integral unit, under the same name and carrying on parts of the same business.

7~~8~~. Rights of Way. The Customer shall, without cost to the Company, grant the Company a right of way for the Company's lines and apparatus across and upon the property owned or controlled by the Customer, necessary or incidental to the supplying of Electric Service and shall permit access thereto by the Company's employees at all reasonable hours.

~~RULE C~~
~~SERVICE AND LIMITATIONS (Continued)~~

~~Idaho Power Company~~
~~Uniform Service Agreement~~

~~Account No.~~ ____

~~THIS AGREEMENT Made this~~ ____ ~~day of~~ ____, ~~20~~ ____ ~~between~~ ____, ~~whose billing address is~~ ____ ~~hereinafter, called Customer and IDAHO POWER COMPANY, a corporation with its principal office located at 1221 West Idaho Street, Boise, Idaho, hereinafter called Company.~~

~~NOW THEREFORE, The parties agree:~~

~~1. Idaho Power agrees to supply~~ ____ ~~volt, three phase Electric Service up to the amount of~~ ____ ~~kilowatts per months pursuant to the Company's Tariff as approved or subsequently amended by the Oregon Public Utility Commission for the Customer's~~ ____ ~~facilities located at or near~~ ____, ~~County of~~ ____, ~~State of Oregon.~~

~~2. The availability of power in excess of the amount stated in Paragraph 1 above is not guaranteed and its taking by the Customer may result in a complete or partial curtailment of service to the Customer. The Company has the right to install, at the Customer's expense, any device necessary to protect the Company's system from damage that may be caused by the taking of power in excess of that stated in Paragraph 1. The Customer shall be responsible for any damages to the Customer's system or damages to third parties resulting from the Customer's taking of power in excess of that stated in Paragraph 1.~~

~~3. The term of this Agreement shall be the period during which the Customer is continuously receiving service from the Company under a standard Tariff Schedule or until 30 days following written notification from the Customer to the Company of the Customer's intent to terminate the Agreement or until 60 days following written notification from the Company to the Customer that one of the following conditions exists:~~

~~a. The Customer's greatest monthly metered Demand during the most current twelve consecutive Billing Periods is less than 80 percent of the kilowatts stated in Paragraph 1, or~~

~~b. The Customer's metered Demand during each of the most current twelve consecutive Billing Periods has not equaled or exceeded 1,000 kW, or~~

~~c. The Customer's metered Demand during any Billing Period exceeds the kilowatts stated in Paragraph 1.~~

~~4. Customers whose load requirements are changing or whose Uniform Service Agreement with the Company has been terminated due to any condition, may request the Company enter into a new Uniform Service Agreement with the Customers.~~

~~5. This Agreement and the rates, terms, and conditions of service set forth or incorporated herein, and the respective rights and obligations of the parties here under, shall be subject to valid laws and to the regulatory authority and orders, rules, and regulations of the Oregon Public Utility Commission and such other administrative bodies having jurisdiction. Nothing herein shall be construed as limiting the Oregon Public Utility Commission from changing any terms, rates, charges, classification of service, or any rules, regulations or~~

~~conditions relating to service under this Agreement, or construed as affecting the right of the Company or the Customer to unilaterally make application to the Commission for any such change.~~

~~RULE C~~
~~SERVICE AND LIMITATIONS (Continued)~~

~~6. In any action at law or equity commenced under this Agreement and upon which judgment is rendered the prevailing party, as part of such judgment, shall be entitled to recover all costs, including reasonable attorneys fees, incurred on account of such action.~~

~~This Uniform Service Agreement replaces and supersedes the Uniform Service Agreement between the parties dated the ____________ day of ____________________, 20_____.~~

~~Date ____, 20_____.~~

~~(Appropriate Signatures)~~

RULE D
METERING

1. Meter Installations. The Company will install and maintain the metering equipment required by the Company to measure power and energy supplied to the Customer. Meter installations will be done at the Company's expense except as specified below or otherwise specified in a schedule. Customer provisions for meter installations will be made in conformance with Company specifications, the National Electrical Code, and/or applicable state or municipal requirements.

a. Instrument Transformer Metering. ~~If the~~ When instrument transformer metering is requested by the Customer ~~specifically requests instrument transformer metering which is~~ but not required by the Company~~,~~ at the time of the initial meter installation, the Customer will be required to pay the cost of such metering equipment and its installation ~~will be paid to the Company by the Customer~~ in accordance with the charges specified in Schedule 66. When a Customer requests instrument transformer metering not required by the Company at a time other than at the time of the initial meter installation, the actual costs will apply.

b. Off-Site Meter Reading Service. Customers taking single-phase service under Schedule 1 or Schedule 7 may request the Company install metering equipment which provides for off-site meter reading. The installation fee and monthly charges for off-site meter reading capability, when the service is requested by the Customer but not deemed to be cost-effective by the Company, are specified in Schedule 66. The Company shall have the sole right to determine whether an installation is cost-effective. Customers who request the Company-installed off-site meter reading equipment be removed within 90 days of initial installation will be assessed a removal fee in accordance with the provisions of Schedule 66. Due to the specialized nature of the metering equipment, a delay may occur between the time a Customer requests the Off-Site Meter Reading Service and the time the equipment is available for installation. Customers utilizing the Off-Site Meter Reading Service may be required to periodically permit Company personnel access to the meter in order for maintenance to be performed.

c. Load Profile Metering. The Company will install, at the Customer's request, the metering equipment necessary to provide load profile information. The installation fee and monthly charges for load profile capability, when the service is requested by the Customer but not provided by the Company as part of the standard meter installation, are specified in Schedule 66. The options available under the Load Profile Metering Service include Meter Pulse Output Service and Load Profile Recording Service. Customers requesting the Load Profile Recording Service are responsible for providing, at their own expense, a hard-wired phone line to each metering point. Customers who request the Load Profile Metering Service be discontinued within 36 months of initial installation will be assessed a removal fee in accordance with the provisions of Schedule 66.

d. Surge Protection Device Services. At the Customer's request, the following services are available for watt-hour metered Customers only.

i. Installation or Removal. The Company will install or remove, at the Customer's request, a surge protection device supplied by the Customer on the meter base and other utility peripherals to accommodate whole-house surge protection. A Surge Protection Device Installation or Removal Charge will be assessed as specified in Schedule 66.

The Company will not install any surge protection device without proof that the vendor of the surge protection device has executed and delivered to the Company an agreement (in a form acceptable to the Company) which provides for the full defense and indemnification of the Company by the vendor against any claims, suits, or losses associated with such device.

RULE D
METERING
(Continued)

d. Surge Protection Device Services (Continued)

Any surge protection device the Company is requested to install on the meter must be Underwriters' Laboratories, Inc. certified and meet National Electric Energy Testing, Research and Application Centers (NEETRAC) test standards or comparable test standards.

ii. Surge Protection Device Customer Visit Charge.

(1) If a surge protection device installation visit results in the inability of Company personnel to install the surge protection device due to safety concerns, inaccessibility to the meter base or other utility access points, or other factors deemed reasonable by the Company, a Surge Protection Device Customer Visit Charge will be applied as specified in Schedule 66. The Company has the sole right to ultimately determine installation feasibility.

(2) Customers who request the Company perform an on-site visit to assess alleged electrical problems believed to be associated with the surge protection product will be charged a Surge Protection Device Customer Visit Charge as specified in Schedule 66 if no problems associated with the electrical service are found as a result of the visit.

e. Primary Voltage Metering. The Company will install, at its own expense, a maximum of one primary voltage meter at a single Premises to record usage taken at 12.5 kV or 34.5 kV.

2. Measurement of Energy. Except as otherwise specifically provided, all energy delivered by the Company will be billed according to measurement by meters located at or near the Point of Delivery.

If the Company is unable to read a Customer's meter because of reasons beyond the Company's control, such as weather conditions or the inability to obtain access to the Customer's Premises, the Company may estimate the meter reading for the Billing Period on the basis of the Customer's previous use, season of the year and use by similar Customer's of the same class in that service area. Bills rendered on estimated readings will be so designated on the bill. The amount of such estimated bill will be subsequently adjusted, as necessary, when the next actual reading is obtained.

Should the Company be unable to read a Customer's meter for two consecutive Billing Periods, the Company will diligently attempt to contact the Customer by telephone and/or letter, to apprise the Customer of the necessity of a meter reading and to make arrangements to read the meter or request the Customer to record and return the meter reading on a card provided by the Company. If such arrangements cannot be made or if the Customer fails to return the meter reading card, the Company may estimate the meter reading.

3. Failure to Register. If the Company's meters fail to register at any time, the service delivered and energy consumed during such period of failure will be determined by the Company on the basis of the best available data. If any appliance or wiring connection, or any other device, is found on the Customer's Premises which prevents the meters from accurately recording the total amount of energy used on the Premises, the Company may at once remove any such wiring connection or appliance, or device, at the Customer's expense, and will estimate the amount of energy so consumed and not registered as accurately as it is able so to do, and the Customer will pay for any such energy within 5 days after being billed, in accordance with such estimate.

RULE D
METERING
(Continued)

4. Meter Tests. The Company will test and inspect its meters from time to time and maintain their accuracy of registration in accordance with generally accepted practices and with OAR 860-023-0015. The Company will, without charge, test the accuracy of registration of a meter upon request of a Customer, provided that the Customer does not request such a test more frequently than once in a 12-month period. If more than one requested test is performed within a 12-month period, the Customer will be required to pay in advance the estimated cost of a special meter test as specified in Schedule 66. The Company will refund the amount paid by the Customer for the test if the results of the test show the average registration error of the meter exceeds ±2 percent.

5. Transformer Losses. When delivery of service is on the primary side of the Customer's transformers, the Company may install its meters on the secondary side of the transformers, and, unless otherwise provided in the schedule, in determining the monthly consumption of power and energy, transformer losses and other losses occurring between the Point of Delivery and the meters will be computed and added to the reading of such meters.

6. Meter Reading. Meters will be read to the last kWh registered, normally at intervals of approximately 30 days. In no case will the meter reading interval exceed 45 days.

RULE E

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RULE F
SERVICE ~~CONNECTION~~ ESTABLISHMENT AND DISCONTINUANCE

1. Service Establishment. A Service Establishment Charge as specified in Schedule 66, unless otherwise specified in a different schedule, will be assessed upon initiating metered service with the Company if service at the Point of Delivery is currently energized. The applicable charge will be billed with the first regular bill.

a. Owners or managers of rental property that arrange with the Company to provide continuous service between tenants will not be assessed a Service Establishment Charge when the service reverts to the responsible party as arranged.

2. Continuous Service. At the request of owners or managers of rental property, the Company will provide continuous service between tenant occupancy. Continuous Service Reversion Charge, as specified in Schedule 66, will be assessed each time the service reverts to the responsible party as arranged.

3. Service Connection. Where service at the specified Point of Delivery is currently disconnected from the Company's system, a Service Connection Charge as specified in Schedule 66 will be assessed at the time service is connected. The Service Connection Charge applies to all service connections for both metered and unmetered service and will be billed with the first regular bill. The Service Establishment Charge does not apply when service is reconnected.

4~~2~~. Service Discontinuance. At the Customer's request, the Company will disconnect service during normal working hours. There is no charge for discontinuing service.

a. When a Customer requests service be discontinued, service will not be disconnected if another party has agreed to accept responsibility for service at the Point of Delivery. Upon initiating service, the Customer requesting service will be billed a Service Establishment Charge in accordance with this rule.

5~~3~~. Termination Practices. The Company's practices relating to Termination of Service are governed by the Oregon Administrative Rules (OAR) of the Oregon Public Utility Commission, in effect at the time the event occurred which required application of the OAR. If the Company's Rules and Regulations on file with the Oregon Public Utility Commission contain provisions which conflict with the OAR, the provisions of the OAR supersede those included in the Company's Rules and Regulations.

6~~4~~. Field Visit. ~~The Company may assess the Customer the~~ A Field Visit Charge, as specified ~~shown on Schedule~~in Schedule 66, ~~whenever the~~ will be assessed when a Company representative visits a service address intending to ~~reconnect or~~ disconnect or connect service, but due to ~~the~~ Customer~~'s~~ action, the Company representative is unable to complete the ~~reconnection or~~ disconnection or connection at the time of the visit. ~~If a payment is collected at the service address, the Company employee accepting payment will not dispense change for payment tendered in excess of the amount due or owing. Any excess payment shall be credited to the Customer's account.~~

7~~5~~. Unauthorized Reconnection. Where damage to the Company's facilities has occurred due to tampering or where reconnection of service has been made by other than the Company, an Unauthorized Reconnection Charge may be collected as specified in Schedule 66. This charge is not a waiver by the Company of the rights to recover losses due to tampering. In addition to the above-mentioned charge, the C~~c~~ustomer receiving service shall be liable for any damage to Company property.

RULE G
BILLINGS

1. Fractional Periods. When the Customer's Billing Period is less than 27 days or greater than 36 days, the Energy Charge for ~~Upon initiating or discontinuing~~ service under Schedules 1, 7, 9, 19, or 24 the Energy Charge will be calculated using actual meter readings. The Energy Charge for services provided under Schedule 40 will be determined using the daily kWh calculated on the basis of load size and number of units served multiplied by the actual number of days since the account was opened or since the previous billing, where appropriate. The proration of the applicable Demand Charge, Basic Charge, Facilities Charge, and Service Charge specified in the appropriate schedule will be calculated by dividing the charge by 30 and multiplying the result by the actual number of days since the account was opened or since the previous meter reading, where appropriate. However, the prorated Service Charge for Schedules 1, 7, 9, 19, or 24 or the Minimum Charge for Schedule 40, will be no less than the amount specified in Schedule 66. For Schedule 15, the proration of the applicable Monthly Charge will be calculated by dividing the charge by 30 and multiplying the result by the actual number of days since the account was opened or the previous billing, where appropriate; however, in no event will the charge be less than the Fractional Period Minimum Billings amount specified in Schedule 66.

2. Corrected Billings. Whenever it is determined that a Customer was billed under an inappropriate schedule, the Customer will be rebilled under the appropriate schedule, except if the Company selected the schedule on the basis of available information and acted in good faith, the Company will not be required to rebill or adjust billings. The rebilling period will be no more than the 3-year period as provided by OAR 860-021-0135.

If the average error for any meter test exceeds ±2 percent, corrected billings will be prepared. The corrected billings will not exceed 6 months if the time when the malfunction or error began is unknown. If the time when the malfunction or error began is known, the corrected billings will be from that time, but will not exceed the 3 year period as provided by OAR 860-021-0135. The Company shall provide written notice to the Customer detailing the circumstances, time period, and adjustment amount of an over or underbilling. If an underbilling occurs, the Company will offer and enter into reasonable payment arrangements with the Customer. The Customer shall be notified in writing of the opportunity for time payments and of the Commission's dispute resolution process. For any overbillings, the Customer will have the choice of a refund or a credit on future bills.

3. Due Dates. The Company's practices relating to Due Dates are governed by the Oregon Administrative Rules (OAR) of the Oregon Public Utility Commission, in effect at the time the event occurred which required application of the OAR. If the Company's Rules and Regulations on file with the Oregon Public Utility Commission contain provisions which conflict with the OAR, the provisions of the OAR supersede those included in the Company's Rules and Regulations.

4. Returned Checks. Checks or payments remitted by Customers in payment of bills are accepted conditionally. A Returned Check Charge, as specified in Schedule 66, will be assessed the Customer for handling each check or payment upon which payment has been refused by the bank.

5. Temporary Suspension of Demand. When the Customer is obliged temporarily to suspend operation due to strikes, action of any governmental authority, acts of God or the public enemy, the Customer may procure a proration of the monthly Billing Demand based upon the period of such suspension by giving immediate written notice to the Company. However, all monthly Minimum Charges and/or obligations will continue to apply as specified in the applicable schedule or a written agreement.

RULE H
NEW SERVICE ATTACHMENTS AND DISTRIBUTION LINE INSTALLATIONS OR ALTERATIONS

This rule applies to requests for electric service under Schedules 1, 7, 9, 19, and 24, that require the installation, alteration, relocation, removal, or attachment of Company-owned distribution facilities. New construction beyond the Point of Delivery for Schedule 9 or Schedule 19 is subject to the provisions for facilities charges under those schedules. This rule does not apply to transmission or substation facilities, or to requests for electric service that are of a speculative nature.

1. Definitions

Additional Applicant is a person or entity whose Application requires the Company to provide new or relocated service from an existing section of distribution facilities with a Vested Interest.

Applicant is a person or entity whose Application requires the Company to provide new or relocated service from distribution facilities that are free and clear of any Vested Interest.

Application is a request by an Applicant or Additional Applicant for new electric service from the Company. The Company, at its discretion, may require the Applicant or Additional Applicant to sign a written application.

Company Betterment is that portion of the Work Order Cost of a Line Installation, alteration, and/or Relocation that provides a benefit to the Company not required by the Applicant or Additional Applicant. Increases in conductor size and work necessitated by the increase in conductor size are considered a Company Betterment if the Connected Load added by the Applicant or Additional Applicant is less than 100 kilowatts. If, however, in the Company's discretion, it is determined that the additional Connected Load added by the Applicant or Additional Applicant, even though less than 100 kilowatts, is (1) located in a remote location, or (2) a part of a development or project which will add a load greater than 100 kilowatts, the Company will not consider the work necessitated by the load increase to be a Company Betterment.

Connected Load is the total nameplate kW rating of the electric loads connected for commercial, industrial, or irrigation service. Connected Load for residences is considered to be 25 kW for residences with electric space heat and 15 kW for all other residences.

Fire Protection Facilities are water pumps and other fire protection equipment, served separately from the Applicant's other electric load, which operate only for short periods of time in emergency situations and/or from time to time for testing purposes.

Line Installation is any installation of new distribution facilities (excluding Relocations or alteration of existing distribution facilities) owned by the Company.

Line Installation Allowance is the portion of the estimated cost of a Line Installation funded by the Company.

Line Installation Charge is the partially refundable charge assessed an Applicant or Additional Applicant to be paid to the Company prior to the construction of the Line Installation, in accordance with Section II.I. "Terms of Payment".

RULE H
NEW SERVICE ATTACHMENTS AND
DISTRIBUTION LINE INSTALLATIONS
OR ALTERATIONS
(Continued)

1. Definitions (Continued)

Multiple Occupancy Projects are projects that are intended to be occupied by more than four owners or tenants. Examples include, but are not limited to, condominiums and apartments.

Relocation is a change in the location of existing distribution facilities.

Residence is a structure built primarily for permanent domestic dwelling. Dwellings where tenancy is typically less than 30 days in length, such as hotels, motels, camps, lodges, clubs, and structures built for storage or parking do not qualify as a Residence.

Subdivision is the division of a lot, tract, or parcel of land into two or more parts for the purpose of transferring ownership or for the construction of improvements thereon, that is lawfully recognized and approved by the appropriate governmental authorities.

Temporary Line Installation is a Line Installation for electric service of 18 calendar months or less in duration.

Temporary Service Attachment is a service attachment to a Customer provided temporary pole which typically furnishes electric service for construction.

Terminal Facilities include transformer, meter, service cable, and underground conduit (where applicable).

Underground Service Attachment Charge is the non-refundable charge assessed an Applicant or Additional Applicant whenever new single phase underground service is required by a Schedule 1 or Schedule 7 customer attaching to the Company's distribution system.

Unusual Conditions are construction conditions not normally encountered. These conditions may include, but are not limited to: frost, landscape replacement, road compaction, pavement replacement, chip-sealing, rock digging, boring, nonstandard facilities or construction practices, and other than available voltage requirements.

Vested Interest is the right to a refund that an Applicant or Additional Applicant holds in a specific section of distribution facilities when Additional Applicants attach to that section of distribution facilities.

Vested Interest Charge is an amount collected from an Additional Applicant for refund to a Vested Interest Holder.

Vested Interest Holder is a person or an entity that has paid a refundable Line Installation Charge to the Company for a Line Installation under either the provisions of the existing Rule H or the provisions of a previous Rule H whichever is applicable as per the Existing Agreements provisions of this rule.

RULE H
NEW SERVICE ATTACHMENTS AND
DISTRIBUTION LINE INSTALLATIONS
OR ALTERATIONS
(Continued)

1. Definitions (Continued)

Vested Interest Refund is a refund payment to an existing Vested Interest Holder resulting from a Vested Interest Charge to an Additional Applicant.

Vested Interest Portion is that part of the Company's distribution system in which a Vested Interest is held.

Work Order Cost is a cost estimate performed by the Company for a specific request for service by an Applicant or Additional Applicant. The Applicant or Additional Applicant shall be responsible for the costs associated with the overhead construction, including, but not limited to, poles, conductors, transformers, meters, and any required permits, less applicable Line Installation Allowances. The Applicant or Additional Applicant shall be responsible for the costs associated with the underground construction, including, but not limited to, conduit, trenching, boring, excavating, backfilling, ducts, raceways, road crossings, paving, vaults, transformers, transformer pads, conductors, meters, and any required permits, less applicable Line Installation Allowances. The Work Order Cost will include general overheads limited to 1.5 percent. General overheads in excess of 1.5% will be funded by the Company.

2. General Provisions

a. Cost Information - The Company will provide cost information as reflected in the charges contained in this rule, to potential Applicants and/or Additional Applicants. This preliminary information will not be considered a formal cost quote and will not be binding on the Company or Applicant but rather will assist the Applicant or Additional Applicant in the decision to request a formal cost quote. Upon receiving a request for a formal cost quote, the Applicant or Additional Applicant will be required to prepay non-refundable engineering costs to the Company.

b. Ownership - The Company will own all distribution Line Installations and retain all rights to them.

c. Rights-of-Way - The Company will construct, own, operate, and maintain lines only along public streets, roads, and highways that the Company has the legal right to occupy, and on public lands and private property across which rights-of-way satisfactory to the Company may be obtained at the Applicant's or Additional Applicant's expense.

d. Removals - The Company reserves the right to remove any distribution facilities that have not been used for one year. Facilities shall be removed only after providing 60 days written notice to the last Customer of record and the owner of the property served, giving them a reasonable opportunity to respond.

e. Property Specifications - Applicants or Additional Applicants must provide the Company with final property specifications as required and approved by the appropriate governmental authorities. These specifications may include but are not limited to: recorded plat maps, utility easements, final construction grades, and property pins.

RULE H
NEW SERVICE ATTACHMENTS AND
DISTRIBUTION LINE INSTALLATIONS
OR ALTERATIONS
(Continued)

2. General Provisions (Continued)

f. Undeveloped Subdivisions - When electric service is not provided to the individual spaces or lots within a Subdivision, the Subdivision will be classified as undeveloped.

g. Mobile Home Courts - Owners of mobile home courts will install, own, operate, and maintain all termination poles, pedestals, meter loops, and conductors from the Point of Delivery.

h. Conditions for Start of Construction - Construction of the Line Installations and/or Relocations will not be scheduled until the Applicant or Additional Applicant pays the appropriate charges to the Company. Appropriate charges include, but are not limited to, engineering fees, work order costs, right-of-way or permit charges, and vested interest payments.

i. Terms of Payment – All payments listed under this section will be paid to the Company in cash 30 days prior to the start of Company construction, unless mutually agreed otherwise.

j. Interest on Payment - If the Company does not start construction on a Line Extension and/or Relocation within 30 days after receipt of the construction payment, the Company will compute interest on the payment amount beginning on the 31st day and ending once Company construction actually begins. Interest will be computed at the rate applicable under the Company's Rule F. If this computation results in a value of $10.00 or more, the Company will pay such interest to the Applicant, Additional Applicant, or subdivider. Construction payment includes, but is not limited to, payment for work order costs, right-of-way or permit charges, and vested interest payments.

k. Fire Protection Facilities - The Company will provide service to Fire Protection Facilities when the Applicant pays the full costs of the Line Installation including Terminal Facilities, less Company Betterment. These costs are not subject to a Line Installation Allowance, but are eligible for Vested Interest Refunds under Section 6.a.

l. Customer Provided Trench Digging and Backfill - The Company will at its discretion allow an Applicant, Additional Applicant or subdivider to provide trench digging and backfill. The Customer will sign a Memorandum of Agreement, detailing the work to be performed by the Customer and the specifications that must be met prior to the start of construction. The Applicant shall be responsible for the current and reasonable future costs associated with the Line Installation's conduit system, which may include, but is not limited to, the costs of trenching, boring, excavating, backfilling, ducts, raceways, road crossings, paving, vaults, transformer pads, and any required permits. The Company shall own and maintain the conduit system once Company conductors have been installed. In a joint trench, backfill must be provided by the Company. Costs of Customer provided trench and backfill will be removed or not included in the Work Order Costs and will not be subject to refund.

RULE H
NEW SERVICE ATTACHMENTS AND
DISTRIBUTION LINE INSTALLATIONS
OR ALTERATIONS
(Continued)

3. Line Installation Allowances

The Company will contribute an allowance for the Terminal Facilities necessary for service attachments and/or Line Installations. A Line Installation Allowance will be applied to the Line Installation costs for a Subdivision as outlined in Section 4.a.i. Subdividers may recoup their payments only through the refunding provisions under Section 6 of this rule.

	Maximum Allowance
Schedule 1	
Residence	Overhead Terminal Facilities + $1000
Non-Residence	Cost of Meter Only
Multiple Occupancy Projects	
Single Phase	Overhead Terminal Facilities
Three Phase	80% of Terminal Facilities
Schedule 7	
Single Phase	Overhead Terminal Facilities
Three Phase	80% of Terminal Facilities
Schedule 9	
Single Phase	$1726
Three Phase	80% of Terminal Facilities
Schedule 24	
Single Phase	$1726
Three Phase	Overhead Terminal Facilities
Schedule 19	
Secondary Service	No Allowances
Primary Service	No Allowances
Transmission Service	No Allowances

4. Charges for Line Installations and Additional Charges for Underground Service Attachments

An Applicant or Additional Applicant will pay the Company for construction of Line Installations and/or underground service attachments, less Line Installation Allowances, based upon the charges listed in this section.

a. Line Installation Charge

If a Line Installation is required, the Applicant or Additional Applicant will pay a partially refundable Line Installation Charge equal to the Work Order Cost less applicable Line Installation Allowances. The Line Installation Charge will be paid to the Company in cash 30 days prior to the start of Company construction, unless mutually agreed otherwise.

RULE H
NEW SERVICE ATTACHMENTS AND
DISTRIBUTION LINE INSTALLATIONS
OR ALTERATIONS
(Continued)

4. Charges for Line Installations and Additional Charges for Underground Service Attachments (Continued)

Inside a Residential Subdivision, the Line Installation Charges are calculated using the Work Order Cost less Terminal Facilities. If a developer is installing the final primary or secondary line to serve the Customer, the developer is entitled to the Terminal Facilities allowance and an $800 lot refund when a permanent residential connection is made on the lot. If the lot purchaser is making the final primary or secondary line installation, the lot purchaser is entitled to the Terminal Facilities allowance, if needed, and up to $800 applied to the Line Installation costs. The developer will not receive the $800 lot refund to the extent an allowance has been given to a lot purchaser. The maximum refund will be the total per lot refund amount as specified in Section 6.b., but not more than the Work Order Cost less Terminal Facilities. Costs of new facilities outside Subdivisions are subject to Vested Interest Refunds. Costs of new Line Installations inside Subdivisions are not subject to Vested Interest Refunds.

Inside a non-Residential Subdivision, the subdivider is required to pay for the installation of the backbone with no allowances. The applicable Terminal Facilities allowance is provided to the Customer requesting service to the lot. The applicable Terminal Facilities allowances are as follows:

	Maximum Allowance
Schedule 7	
Single Phase	Overhead Terminal Facilities
Three Phase	80% of Terminal Facilities
Schedule 9	
Single Phase	Overhead Terminal Facilities
Three Phase	80% of Terminal Facilities

b. Underground Service Attachment Charge

Each Applicant or Additional Applicant will pay a non-refundable Underground Service Attachment Charge for attaching new Terminal Facilities to the Company's distribution system. The Company will determine the location and maximum length of service cable.

RULE H
NEW SERVICE ATTACHMENTS AND
DISTRIBUTION LINE INSTALLATIONS
OR ALTERATIONS
(Continued)

4. Charges for Line Installations and Additional Charges for Underground Service Attachments (Continued)

b. Underground Service Attachment Charge (Continued)

Schedule 1, 7, and 9 Single Phase (Limited to a maximum of 400 Amps

Underground Service Cable	
(Base Charge plus Distance Charge)	
Base Charge	
from underground	$40.00
from overhead including 2" riser	$395.00
from overhead including 3" riser	$520.00
Distance Charge (per foot)	
Company Installed Facilities (per foot)	
with 1/0 underground cable	$6.90
with 4/0 underground cable	$7.50
with 350 underground cable	$9.60
Customer Provided Trench & Conduit (per foot)	
with 1/0 underground cable	$2.15
with 4/0 underground cable	$3.60
with 350 underground cable	$4.65

c. Vested Interest Charge

Additional Definitions for Section 4.c. and Section 6.a.:

Original Investment - Work Order Cost less the Allowance for Terminal Facilities.

Vested Interest Holder's Contribution - Customer Payment plus Line Installation Allowances other than Terminal Facilities.

Vested Interest - Amount potentially subject to refund.

Load Ratio - Additional Applicant load divided by the sum of Additional Applicant's load and Vested Interest Holder's load.

Distance Ratio - Additional Applicant distance divided by original distance.

i. The initial Applicant will pay the original investment cost less any allowances. An Additional Applicant connecting to a Vested Interest Portion will have two options:

Option One - An Additional Applicant may choose to pay the current Vested Interest Holder's Vested Interest, in which case the Additional Applicant will become the Vested Interest Holder and, as such, will become eligible to receive Vested Interest Refunds up to that new Vested Interest Holder's contribution less 20 percent of the original investment.

RULE H
NEW SERVICE ATTACHMENTS AND
DISTRIBUTION LINE INSTALLATIONS
OR ALTERATIONS
(Continued)

4. Charges for Line Installations and Additional Charges for Underground Service attachments (Continued)

Option Two – An additional Applicant may choose to pay an amount determined by this equation:

Vested Interest payment = Load Ratio x distance Ratio x Vested Interest Holder's unrefunded contribution.

c. Vested Interest Charge (Continued)

If Option Two is selected, the Additional Applicant has NO vested Interest and the previous Vested Interest Holder remains the Vested Interest Holder. The Vested Interest Holder's Vested Interest will be reduced by the newest Additional Applicant's payment.

ii. The Vested Interest Charge will not exceed the sum of the Vested Interests in the Vested Interest Portion.

iii. If an Additional Applicant connects to a Vested Interest Portion which was established under a prior rule or schedule, the Vested Interest Charges of the previous rule of schedule apply to the Additional Applicant.

5. Other Charges

All charges in this section are non-refundable.

a. Relocation and Removal Charges – If an Applicant or Additional applicant requests a Relocation or removal of Company facilities, the Applicant or Additional applicant will pay a non-refundable charge equal to the Work Order Cost.

b. Engineering Charge – Applicants or Additional Applicants will be required to prepay all engineering costs for Line Installations, and/or Relocation. Engineering charges will be calculated at $44.00 per hour.

c. right-of-Way Charge – A pplicants or Additional Applicants will be responsible for any costs associated with the acquisition of right-of-way.

d. Temporary Line Installation Charge – Applicants or Additional Applicants will pay the installation and removal costs of providing Temporary Line Installations.

e. Temporary Service Attachment Charge – Applicants or Additional Applicants will pay for Temporary Service Attachments as follows:

i. Underground - $140.00

The Customer provided pole must be set within two linear feet of the Company's existing transformer or junction box.

RULE H
NEW SERVICE ATTACHMENTS AND
DISTRIBUTION LINE INSTALLATIONS
OR ALTERATIONS
(Continued)

5. Other Charges (Continued)

e. Temporary Service Attachment Charge (Continued)

ii. Overhead - $120

The Customer provided pole shall be set in a location that does not require more than 100 feet of #2 aluminum service conductor that can be readily attached to the permanent location by merely relocating it.

The electrical facilities provided by the Customer on the pole shall be properly grounded, electrically safe, and ready for connection to Company facilities.

The Customer shall obtain all permits required by the applicable state, county, or municipal governments and will provide copies or verification to the Company as required. The above conditions must be satisfied before the service will be attached. Refer to Schedule 66 Temporary Service Return Trip for charges if these conditions are not satisfied.

f. Unusual Conditions - Applicants, Additional Applicants, and subdividers will pay the Company the additional costs associated with any Unusual Conditions included in the Work Order Cost related to the construction of a Line Installation or Relocation. This payment, or portion thereof, will be refunded to the extent that the Unusual Conditions are not encountered. Unusual Conditions payments for Line Installations will also be refunded, under the provisions of Section 6I, if the Unusual Conditions are encountered.

In the event that the estimate of the Unusual Conditions included in the Work Order Cost exceeds $10,000, the Applicant, Additional Applicant or subdivider may either pay for the Unusual Conditions or may furnish an Irrevocable Letter of Credit drawn on a local bank or local branch office issued in the name of Idaho Power Company for the amount of the Unusual Conditions. Upon completion of that portion of the project which included an Unusual Conditions estimate, Idaho Power Company will bill the Applicant, Additional Applicant or subdivider for the amount of Unusual Conditions encountered up to the amount established in the Irrevocable Letter of Credit. The Applicant, Additional Applicant or subdivider will have 15 days from the issuance of the Unusual Conditions billing to make payment. If the Applicant, Additional Applicant or subdivider fails to pay the Unusual Conditions bill within 15 days, Idaho Power will request payment from the bank.

g. Joint Trench - Applicants, Additional Applicants, and subdividers will pay the Company for trench and backfill costs included in the work order prepared for an unshared trench. In the event that the Company is able to defray any of the trench and backfill costs included in the work order through the sharing of the trench with other utilities, the trench and backfill cost savings will be refunded.

RULE H
NEW SERVICE ATTACHMENTS AND
DISTRIBUTION LINE INSTALLATIONS
OR ALTERATIONS
(Continued)

6. Refunds

a. Vested Interest Refunds - The initial Applicant will be eligible to receive up to 80 percent of the original investment as a Vested Interest Refund in accordance with Section 4.c. Refunds will be funded by the Additional Applicant's Vested Interest Charge as calculated in accordance with Section 4.c. A Vested Interest Holder and the Company may agree to waive the Vested Interest payment requirements of Additional Applicants with loads less than an agreed upon level. Waived Additional Applicants would not be considered Additional Applicants for purposes of Section 6.a.i.(a).

i. Vested Interest Refund Limitations

(1) Except for Rule 6.c. Vested Interest Refunds will be funded by no more than four Additional Applicants during the 5 year period following the completion date of the Line Installation for the initial Applicant.

(2) In no circumstance will refunds exceed 100 percent of the refundable portion of any party's cash payment to the Company.

b. Subdivision Refunds

i. A subdivider will be eligible for Vested Interest Refunds for payments for Line Installations outside the subdivision.

ii. A subdivider will be eligible for a refund from the Company on the Line Installation Charge inside the Subdivision when a permanent Residence connects for service and occupies a lot inside the Subdivision within 5 years from the construction completion date of the Line Installation for the Subdivision.

iii. The amount refunded to subdividers of residential Subdivisions will be $800 per lot, less any additional Line Installation costs required to provide connected service to the lot.

7. Line Installation Agreements

When the Line Installation Allowance paid by the Company under the provisions of this rule equals or exceeds $75,000, the Applicant will be required to contract to pay, for a period of 5 years following the completion date of the Line Installation, an annual payment equal to the greater of the billings determined by application of the appropriate schedule or:

a. Eighty percent of the Applicant's total annual bill as determined by application of the appropriate schedule; plus;

RULE H
NEW SERVICE ATTACHMENTS AND
DISTRIBUTION LINE INSTALLATIONS
OR ALTERATIONS
(Continued)

7. Line Installation Agreements (Continued)

b. Twenty percent of the Line Installation Allowance granted the Applicant.

Each Line Installation, for which the Line Installation Allowance paid equals or exceeds $75,000, will require a separate Uniform Distribution Line Installation Agreement between the Applicant and the Company.

Developers of multi-family residential dwellings in which each unit is separately metered will be exempt from the requirement to enter into an agreement with the Company if the Line Installation Allowance paid equals or exceeds $75,000.

8. Existing Agreements

This rule shall not cancel existing agreements, including vested interest payments and refund provisions, between the Company and previous Applicants, or Additional Applicants. All applications of Additional Applicants will be governed and administered under the rule or schedule in effect at the time the original Application was received and dated by the Company.

If an Additional Applicant requires the installation of new or altered distribution facilities, the Additional Applicant will also be the Original Applicant for the new or altered distribution facilities. As the Original Applicant, the payment for such new or altered distribution facilities will be subject to the rule in effect at the time of the Additional Applicant's Application for new or altered distribution facilities is received and dated by the Company. Accordingly, an Additional Applicant can be simultaneously an Original Applicant with separate provisions for vested interest payments and refunds.

9. Relocation or Removal of Facilities

a. Generally - Any relocation of Facilities for a requesting party, including builders, developers, Customers or Customers' agents, that is for their convenience will be performed by the Company at the requesting party's expense. The Company may require payment in advance of a sum equal to the estimated original cost of installed facilities to be removed, less estimated salvage and less depreciation, plus estimated removal cost, plus any operating expense associated with the removal or relocation.

b. Public Works Project - Under the following circumstances, the cost for relocation or removal of facilities within the public right-of-way will be borne by the Company unless an ordinance, legislation or private agreement specifies other cost responsibilities:

i. The rearrangement can be identified to be for a public works project. Examples of public works projects include but are not limited to public transit or a road widening financed by public funds;

RULE H
NEW SERVICE ATTACHMENTS AND
DISTRIBUTION LINE INSTALLATIONS
OR ALTERATIONS
(Continued)

9. Relocation or Removal of Facilities (Continued)

b. Public Works Project (Continued)

ii. Reasonable notice is provided to the Company;

iii. The overall project can generally be scheduled during normal work hours (excluding load transfers which may need to be performed outside of normal work hours); and

iv. The public works project does not require the Company to make temporary relocations.

c. Easement - Costs for permanently relocating facilities located on an easement will be borne by the requesting party regardless of status as public works or otherwise.

d. Permit Job - Where it can be identified that the requesting party has received a permit through a city or county for work within the public right-of-way that is required for the requesting party's construction project, the requesting party is responsible for all of the costs associated with the necessary rearrangement of facilities.

e. Relocation of Overhead or Underground Facilities at Company Expense - If the necessary work can be performed by Company crews in a single trip to the requesting party's Premises during scheduled crew hours, relocation or removal of overhead or underground service distribution facilities on or adjacent to the Premises will be performed at Company expense, under the circumstances listed below. For underground relocations, the requesting party is responsible for any necessary trenching, boring, backfilling, conduit, paving, vaults and pads.

i. Such facilities are idle or will be made idle by changes in the requesting party's electrical arrangement or needs, except in the case of conversion from overhead to underground service; or

ii. The location of such facilities in the street area deprive the requesting party of reasonable ingress to or egress from the Premises, provided such facilities are not on a property line or a property line extended; or

iii. Such facilities occupy space on the requesting party's Premises that will be used for an expansion of the requesting party's building or plant; or

iv. The purpose is to relocate a meter to a more accessible location approved by the Company; or

RULE H
NEW SERVICE ATTACHMENTS AND
DISTRIBUTION LINE INSTALLATIONS
OR ALTERATIONS
(Continued)

9. Relocation or Removal of Facilities (Continued)

e. Relocation of Overhead or Underground Facilities at Company Expense (Continued)

v. Relocation of a service drop is the only work requested. If a second trip is required, no charge is made if the trip can be scheduled when Company crews are normally available and at a time convenient to the Company or, if in the opinion of the Company, a definite improvement in routing or attachment of the service wire will result. In all other circumstances the requesting party shall be charged the cost incurred by the Company to make the second trip.

f. Temporary Relocations - Where the Company is required to temporarily move its facilities either because the Company cannot move its facilities to the new permanent placement or the facilities will be returned to their former location at a later point in time, the costs of the temporary relocation will be borne by the requesting party regardless of status as public works or otherwise. A temporary relocation is defined as any relocation where the Company must move its facilities two or more times within a three-year period.

10. Conversion from Overhead to Underground Service

a. General - The Company will replace overhead facilities with underground facilities whenever such conversion is practicable and economically feasible. Customers connected by overhead distribution facilities owned by the Company that desire underground service shall comply with applicable provisions of this rule.

b. Payment for Service Changes - The party requesting conversion from overhead to underground shall pay the Company, prior to conversion, the original cost, less depreciation, less salvage value, plus removal expense of any existing overhead facilities no longer used or useful by reason of said underground system, and the costs of any necessary rearrangements, modifications, and additions to existing facilities to accommodate the conversion of facilities from overhead to underground.

c. Special Conditions - The conversion of overhead to underground facilities affecting more than one Customer shall be conditioned on the following:

i. The governing body of the city or county in which the Company's facilities are located shall have adopted an ordinance creating an underground district in the area in which both the existing and new facilities are and will be located, providing:

(1). All existing overhead communication equipment and distribution facilities in such district are removed;

RULE H
NEW SERVICE ATTACHMENTS AND
DISTRIBUTION LINE INSTALLATIONS
OR ALTERATIONS
(Continued)

10. Conversion from Overhead to Underground Service (Continued)

c. Special Conditions (Continued)

(2). Each Customer served from such electric overhead facilities shall, in accordance with the Company's rules for underground service, make all necessary electrical facility changes on said Customer's Premises in order to receive service from the Company's underground facilities as soon as available; and

(3). The Company is authorized to discontinue its overhead service on completion of the underground facilities.

ii. All Customers served from overhead facilities shall agree in writing to perform the wiring changes required on their Premises so that service may be furnished in accordance with the Company's rules regarding underground service. Such Customers must also authorize the Company to discontinue overhead service upon completion of the underground facilities.

iii. When the local government requires the Company to convert overhead facilities to underground at the Company's expense, the provisions of OAR 860-022-0046 shall apply.

iv. That portion of the overhead system that is placed underground shall not impair the utilization of the remaining overhead system.

d. Cost of Area Conversions - Area conversions may involve an allocation or assessment of costs and responsibilities among Customers. Such assessment and collection thereof will be the responsibility of a governmental unit or an association of those affected.

e. Cost of Additional Circuit Capacity - Where the Company installs an underground circuit with capacity in excess of the existing overhead, any additional cost to provide such excess circuit capacity will be at the Company's expense. Applicant cost responsibilities shall be as defined in Section B plus all reasonable costs for conduit or vault space installed to establish pathways for future circuit capacity.

RULE H
NEW SERVICE ATTACHMENTS AND
DISTRIBUTION LINE INSTALLATIONS
OR ALTERATIONS
(Continued)

IDAHO POWER COMPANY
Uniform Distribution Line Installation Agreement

DISTRICT ________________________________ ACCOUNT NO.________________________________

THIS AGREEMENT Made this __________ day of ______________________, 20_____, between ____, whose billing address is ____ hereinafter called Customer, and **IDAHO POWER COMPANY,** A corporation with its principal office located at 1221 West Idaho Street, Boise, Idaho, hereinafter called Company:

NOW THEREFORE, The parties agree as follows:

1. The Company will agree to provide facilities to supply _______ volt, ____ phase Electric Service for the Customer's facilities located at or near _____, County of ____________, State of Oregon.

2. The Customer will agree to:

a. Make a cash advance to the Company of $________________ as the Customer's share of the investment in service facilities;

b. Provide rights-of-way for the line extension at no cost to the Company, in a form acceptable to the Company;

c. Pay an annual minimum charge during the first 60 months following the Initial Service Date. The annual minimum charge will be the greater of (1) the total of the schedule billings for the year or (2) $______________ plus 80 percent of the total schedule billings for the year. The total schedule billings will be computed in accordance with the rates and provisions of the schedules under which the Customer received service for that year.

3. This Agreement will not become binding upon the parties until signed by both parties.

4. The initial date of delivery of power and energy is subject to the Company's ability to obtain required labor, materials, equipment, satisfactory rights-of-way and comply with governmental regulations.

5. The term of this Agreement will be for 5 years from and after the Initial Service Date thereof.

6. This Agreement will be binding upon the respective successors and assigns of the Customer and the Company, provided however, that no assignment by the Customer will be effective without the Company's prior written consent. The Company's consent will not be unreasonably withheld.

RULE H
NEW SERVICE ATTACHMENTS AND
DISTRIBUTION LINE INSTALLATIONS
OR ALTERATIONS
(Continued)

Uniform Distribution Line Installation Agreement (Continued)

7. This Agreement is subject to valid laws and to the regulatory authority and orders, rules and regulations of the Oregon Public Utility Commission and such other administrative bodies having jurisdiction as well as Idaho Power Company's Rules and Regulations as now or may be hereafter modified and approved by the Oregon Public Utility Commission.

8. The Company's Rule H, any revisions to that rule, and/or any successor rule is to be considered as part of this Agreement.

9. In any action at law or equity commenced under this Agreement and upon which judgment is rendered, the prevailing party, as part of such judgment, will be entitled to recover all costs, including reasonable attorneys fees, incurred on account of such action.

W. O. No. ______________________________

Initial Service Date ______________________

(APPROPRIATE SIGNATURES)

RULE I
BUDGET PAY PLANS

1. Residential Budget Pay Plan - Schedule 1. A Budget Pay Plan is available to Residential Customers desiring to levelize payments for electric service. If a Customer has more than one electric service on the account, each electric service charge will be levelized individually. A Customer may sign up for the Budget Pay Plan at any time during the year. In order to be eligible for the Budget Pay Plan, the Customer's account must not be in arrears.

The levelized payment will approximate the average of 12 monthly billings based on either the historical charges, or an estimate of future charges. The Budget Pay amount for each electric service on the account will be adjusted to the next higher dollar. Budget Pay amounts will be recalculated at the 12-month (or 365-day) anniversary of the date the Customer began paying the most current Budget Pay amount(s). The new monthly payment will be the recalculated Budget Pay amount(s). A Customer's Budget Pay amount(s) may decrease, increase, or remain the same.

Customers with a negative balance in their Budget Pay Plan account at the time of recalculation will have monthly Budget Pay charges equal to the recalculated Budget Pay amount plus one-twelfth of the negative balance. At the Customer's request, a negative balance may be paid in full. Customers with a positive balance in their Budget Pay Plan account at the time of recalculation, or upon termination of the agreement after all charges for services have been paid, will be refunded at the Customer's request. If no request for refund is made, the monthly Budget Pay charges will be equal to the recalculated Budget Pay amount reduced by one-twelfth of the positive balance. Upon the Customer's request, a positive balance for one Budget Pay electric service may be transferred to the balance of another Budget Pay electric service on the account.

Any estimates furnished by the Company with such Budget Pay Plan should not be construed as a guarantee that the total actual charges will not exceed the estimates. The Company, because of rate changes or other requirements, may at any time submit a revised estimate to the Customer and require that the Customer pay the revised monthly Budget Pay installment as a condition to the continuation of the Budget Pay Plan for the Customer.

The Budget Pay amount(s) will be billed on the regular service bill each month. Once established, the Budget Pay Plan will remain in effect from year to year until the Customer notifies the Company not less than 30 days prior to the desired date of cancellation or unless the Customer fails to pay the agreed amounts.

2. Small General Service Budget Pay Plan - Schedule 7. A Budget Pay Plan is available to Small General Service Customers receiving service on Schedule 7. If a Customer has more than one electric service on the account, each electric service will be levelized individually. If a Customer transfers to another schedule (other than Schedule 1), the Budget Pay Plan will not be available. A Customer may sign up for the Budget Pay Plan at any time during the year.

In order to qualify, the Customer must have been receiving service at the same location, under the same ownership and account number, and with all monthly billings paid on or before the past due date for at least 12 months prior to applying for the Budget Pay Plan. The Customer must maintain the payment status as described above or the Customer will be removed from the Budget Pay Plan on the next monthly billing and all past due balances will become immediately due and payable.

RULE I
BUDGET PAY PLANS
(Continued)

Small General Service Budget Pay Plan - Schedule 7 (Continued)

The levelized payment will approximate the average of 12 monthly billings based on historical charges. Budget Pay amounts will be recalculated at the 12-month (or 365-day) anniversary of the date the Customer began paying the most current Budget Pay amount(s). The Budget Pay amount for each electric service on the account will be adjusted to the next higher dollar. The new monthly payment will be the recalculated Budget Pay amount(s). A Customer's Budget pay amount(s) may decrease, increase, or remain the same.

Customers with a negative balance in their Budget Pay Plan account at the time of recalculation will have monthly Budget Pay charges equal to the recalculated Budget Pay amount plus one-twelfth of the negative balance. At the Customer's request, a negative balance may be paid in full. Customers with a positive balance in their Budget Pay Plan account at the time of recalculation, or upon termination of the agreement after all charges for services have been paid, will be refunded at the Customer's request. If no request for refund is made, the monthly Budget Pay charges will be equal to the recalculated Budget Pay amount reduced by one-twelfth of the positive balance. Upon the Customer's request, a positive balance for one Budget Pay electric service may be transferred to the balance of another Budget Pay electric service on the account.

Any estimates furnished by the Company with such Budget Pay Plan should not be construed as a guarantee that the total actual charges will not exceed the estimates. The Company, because of rate changes or other requirements, may at any time submit a revised estimate to the Customer and require that the Customer pay the revised monthly Budget Pay installment as a condition to the continuation of the Budget Pay Plan for the Customer.

The Budget Pay amount(s) will be billed on the regular service bill each month. Once established, the Budget Pay Plan will remain in effect from year to year until the Customer notifies the Company not less than 30 days prior to the desired date of cancellation or unless the Customer fails to pay the agreed amounts.

RULE J
CONTINUITY, CURTAILMENT AND INTERRUPTION OF ELECTRIC SERVICE

1, Electric service is inherently subject to occasional interruption, suspension, and fluctuation. The Company will have no liability to its Customers or any other persons for any interruption, suspension, curtailment, or fluctuation in service or for any loss or damage caused thereby if such interruption, suspension, curtailment, or fluctuation results from any of the following:

a. Causes beyond the Company's reasonable control including, but not limited to, fire, flood, drought, winds, acts of the elements, court orders, insurrections or riots, generation failures, lack of sufficient generating capacity, breakdowns of or damage to facilities of the Company or of third parties, acts of God or public enemy, strikes or other labor disputes, civil, military or governmental authority, electrical disturbances originating on or transmitted through electrical systems with which the Company's system is interconnected, and acts or omissions of third parties;

b. Repair, maintenance, improvement, renewal or replacement work on the Company's electrical system, which work in the sole judgment of the Company is necessary or prudent; to the extent practicable work shall be done at such time as will minimize inconvenience to the Customer and, whenever practicable, the Customer shall be given reasonable notice of such work.

c. Actions taken by the Company, which in its sole judgment are necessary or prudent to protect the performance, integrity, reliability or stability of the Company's electrical system or any electrical system with which it is inter-connected, which actions may occur automatically or manually.

2. Load curtailment and interruption carried out in compliance with an order by governmental authority shall follow the Company's plan entitled "Load Curtailment and Interruption Procedure", as filed with and approved by the Commission.

3. The provision of this rule do not affect any persons rights in tort.

RULE K
CUSTOMER'S LOAD AND OPERATIONS

1. Interference with Service. The Company reserves the right to refuse to supply loads of a character that may seriously impair service to any other Customers, or may disconnect existing service if it is seriously impairing service to any other Customers. In the case of pump hoist or elevator motors, welders, furnaces, compressors, and other installations of like character where the use of electricity is intermittent, subject to ~~violent~~ voltage fluctuations, ~~or causes~~ voltage notching or draws a nonsinusoidal (harmonically distorted) load current, the Company may require the Customer to provide equipment, at the Customer's expense, to reasonably limit such fluctuations.

2. Practices and Requirements of Harmonic Control. Customers are required to comply with the *Practices and Requirements of Harmonic Control in Electric Power Systems* as set forth in the current Institute of Electrical and Electronic Engineers (IEEE) Standard 519~~-1992~~. The values indicated by IEEE Standard 519 ~~-1992~~ apply at the point where the Company's equipment interfaces with the Customer's equipment.

3. Change of Load Characteristic. The Customer shall give the Company prior notice before making any significant change in either the amount or electrical character of the Customer's electrical load thereby allowing the Company to determine if any changes are needed in the Company's equipment or distribution system. The Customer may be held liable for damages to the Company's equipment resulting from the Customer's failure to provide said notice of change in electrical load.

4. Protection of Electrical Equipment. ~~The Company reserves the right to refuse single phase service to motors larger than 7 ½ horsepower.~~

The Customer is solely responsible for the selection, installation, and maintenance of all electrical equipment and wiring (other than the Company's meters and apparatus) on the load side of the Point of Delivery. The Customer should provide adequate protection for equipment, data, operations, work and property under the Customer's control from system disturbances such as (a) high and low voltage, (b) surges, harmonics, and transients in voltage, and (c) overcurrent. For unidirectional and three-phase equipment, the Customer should provide adequate protection from "single phasing conditions", reversal of phase rotation, and phase unbalance. ~~All motor installations should include effective protection apparatus or have inherent construction within the motor to accomplish equivalent protection as follows:~~

5. Motor Installations. The Company reserves the right to refuse single phase service to motors larger than 7 ½ horsepower.

a. Motor Connection. All motor installations greater than 7 ½ horsepower (HP) must be approved by the Company to determine how the motor's connection will affect the Company's system. Changes to Company facilities necessary to address the effects of, but not limited to, flicker, voltage balance, voltage level, or reactive power may be at the Customer's expense. ~~a. Overload or overcurrent protection for each motor by suitable thermal relays, fuses or circuit interrupting devices automatically controlled to disconnect the motor from the line to protect it from damage caused by over-heating. Installation or protection in each conductor connected to three-phase motors is recommended.~~

~~b. Open phase protection on all polyphase installations to disconnect motors from the line in the event of opening of one phase.~~

~~c. All polyphase motors for the operation of passenger and freight elevators, cranes, hoists, draglines, and similar equipment will be provided with reverse phase relays or equivalent devices, for protection in case of phase reversal.~~

~~d. Motors that cannot safely be subjected to full voltage at starting should be provided with a device to insure that, on failure of voltage such motors will be disconnected from the line. It is also recommended that such device be provided with a suitable time-delay relay.~~

RULE K
CUSTOMER'S LOAD AND OPERATIONS
(Continuous)

5. Motor Installations (Continued)

b. ~~5.~~ Allowable Motor Starting Currents. The starting currents (~~such currents shall be~~ as determined by tests or based on published data by manufacturers) of alternating current motors ~~up to 100 horsepower~~ will not exceed the allowable locked rotor current values shown in the following table, corrections being allowed to compensate for the difference between the voltage supply at the motor terminals and its rated voltage. If the starting current of the motor exceeds the locked rotor current value ~~given in~~ indicated by the table below, a starter must be used or other means employed to limit the starting current to the locked rotor current value specified, except that such starting equipment may be omitted by written permission of the Company where the absence of such starting equipment will not cause objectionable voltages~~ fluctuations~~. Maximum permissible locked rotor current values in the following table apply~~ies~~ to a single motor installation. Starters may be omitted on the smaller motors of an installation consisting of more than one motor when their omission will not result in a current in excess of the allowable locked rotor current of the single largest motor of the group.

	~~Allowable Locked Rotor Currents~~			
	~~Single~~	~~Polyphase Motors~~		
	~~Phase~~	~~240 Volt~~	~~480 Volt~~	~~2,400 Volt~~
~~Rated Size~~	~~240 Volt~~	~~3-phase~~	~~3-phase~~	~~3-phase~~
~~7 1/2 HP~~	~~110 amp~~			
~~10 HP~~	~~147 amp~~	~~141 amp~~	~~71 amp~~	
~~15 HP~~		~~197 amp~~	~~99 amp~~	
~~20 HP~~		~~250 amp~~	~~125 amp~~	
~~25 HP~~		~~304 amp~~	~~152 amp~~	
~~30 HP~~		~~360 amp~~	~~180 amp~~	
~~40 HP~~		~~380 amp~~	~~190 amp~~	
~~50 HP~~		~~400 amp~~	~~200 amp~~	~~40 amp~~
~~60 HP~~		~~480 amp~~	~~240 amp~~	~~48 amp~~
~~75 HP~~		~~600 amp~~	~~300 amp~~	~~60 amp~~
~~100 HP and Over~~		~~Consult Company~~		

	Allowable Locked Rotor Currents*					
	Single Phase Motors		Three Phase Motors			
	208 Volt	240 Volt	208 Volt	240 Volt	480 Volt	Over 480 Volt
Rated Size HP	Starting Amps Allowed					
7.5	127	110				
10			163	141	71	
15			227	197	99	
20			288	250	125	
25			351	304	152	
30			415	360	180	
40			438	380	190	
50			462	400	200	
60			554	480	240	
75			692	600	300	
Over 75						

*Note: If no value is shown, Company approval of the locked rotor current is required prior to motor installation.

RULE L
Deposits

1. Residential Customers. The Company may require a deposit from a residential customer if: (1) the Customer is unable to establish credit as defined in section 1 of OAR 860-021-0200, (2) the Customer has received electric service from either the Company or another Oregon regulated electric utility within the preceding 24 months and at the time service was terminated owed an account balance that was not paid according to its terms for which a dispute was not registered within 60 days of the date service was terminated, or (3~~2~~) was previously terminated for theft of service by the Company or any Oregon regulated utility or was otherwise found to have diverted utility service. In either of these two cases, the Company may require a deposit from the Customer equal to one-sixth of the estimated annual billing at the rates then in effect if the calculated deposit amount exceeds $250. The Company's practices relating to deposit payment arrangements for residential customers are governed by OAR 860-021-0205.

2. Commercial and Special Contract Customers (Schedules 7, 9, 19 and Special Contract). The Company may require a deposit from Commercial or Special Contract customers if: (1) the Customer has been disconnected for nonpayment within the last 12 months; (2) the Customer has received more that two 15-day termination notices within the last 12 months; (3) the Customer becomes a debtor in a bankruptcy proceeding; (4) the Customer falsifies information in the application for service; (5) the Customer fails to establish credit satisfactory to the Company; (6) the nature of the Customer's business is speculative or subject to a high rate of failure; (7) the Customer is applying for service with the Company for the first time; (8) the Customer has an outstanding prior service account with the Company that accrued within the last four years and at the time of application for service remains unpaid and not in dispute; or (9) the risk of future loss is evident based on the Customer's current commercial credit rating; or (10) the Customer requests service be provided for a period of less than 90 days. If any of the criteria (1) through (9) are met, the Company may require a deposit not exceeding two times the Customer's estimated monthly billing at the service address if the calculated deposit amount exceeds $250. When a Customer requests service be provided for less than 90 days, a deposit equal to $100 or twice the estimated monthly billing, whichever is greater, may be required.

A new Customer can establish satisfactory credit by presenting to the Company one of the following: (1) a statement from another electric utility showing the Customer's most recent 12-month credit history during which time the Customer had not received any notices of disconnection; (2) a letter of credit from a major financial institution; or (3) a current Dun and Bradstreet report that substantiates the credit reliability of the Customer. Deposits may be paid in two equal installments; the first installment must be paid at the time of the application for service or upon notice from the Company to existing customers, and the second installment must be paid within 30 days.

3. Written Explanation for Denial of Service or Requirement of Deposit. If the Company denies service or requires a cash deposit as a condition of providing or continuing service, then it will provide a written explanation to the Customer stating the reasons why it denies service or requires a deposit. The applicant or Customer will be given an opportunity to rebut those reasons.

4. Interest on Deposits. Interest on deposits held by the Company shall be accrued at the rate established by the Commission specified in OAR 860-021-0210. Interest shall be computed from the time the deposit is made until it is refunded or applied to the Customer's regular bill. Interest will not accrue on a deposit if service is discontinued temporarily at the request of a Customer who leaves the deposit with the Company for future use as a deposit, or if service has been permanently discontinued and the Company has been unsuccessful in its attempt to refund a deposit.

5. Refund of Deposit. Deposits will be refunded with interest or applied to the next monthly bill (at the Customer's option) if the Customer's account is current and the account has not been disconnected for nonpayment nor been issued more than two 5-day disconnection notices during the previous 12 months.

RULE L
Deposits
(Continued)

6. Retention During Dispute. The Company may retain the deposit pending the resolution of a dispute over termination of service. If the deposit is later returned to the Customer, the Company shall pay interest at the annual rates established in OAR 860-021-0210 for the entire period over which the deposit was held.

7. Transfer of Deposit. Deposits shall not be transferred from one Customer to another Customer or between classes of service, except at the Customer's request. When a Customer with a deposit on file transfers service to a new location within the Company's service area, the deposit shall remain with the Customer at the new location.

SCHEDULE 1
RESIDENTIAL SERVICE

AVAILABILITY

Service under this schedule is available at points on the Company's interconnected system within the State of Oregon where existing facilities of adequate capacity and desired phase and voltage are adjacent to the Premises to be served, and additional investment by the Company for new transmission, substation or terminal facilities is not necessary to supply the desired service.

APPLICABILITY

Service under this schedule is applicable to Electric Service required for residential service Customers for general domestic uses, including single phase motors of 7½ horsepower rating or less, subject to the following conditions:

1. When a portion of a dwelling is used regularly for business, professional or other gainful purposes, or when service is supplied in whole or in part for business, professional, or other gainful purposes, the Premises will be classified as non-residential and the appropriate general service schedule will apply. However, if the wiring is so arranged that the service for residential purposes can be metered separately, this schedule will be applied to such service.

2. Whenever the Customer's equipment does not conform to the Company's specifications for service under this schedule, service will be supplied under the appropriate General Service Schedule.

3. This schedule is not applicable to standby service, service for resale, or shared service.

TYPE OF SERVICE

The type of service provided under this schedule is single phase, alternating current at approximately 120 or 240 volts and 60 cycles, supplied through one meter at one Point of Delivery. Upon request by the owner of multi-family dwellings, the Company may provide 120/208 volt service for multi-family dwellings when all equipment is U L approved to operate at 120/208 volts.

WATER HEATING

Electric storage water heating equipment shall conform to specifications of the Underwriters' Laboratories, Inc., and the Company and its installation shall conform to all National, State, and Municipal Codes and may be equipped with one or two heating units. No single heating unit shall exceed 6 kW; and where two heating units are used in a single tank, these units shall be so interlocked that not more than 6 kW can be connected at any one time.

SCHEDULE 1
RESIDENTIAL SERVICE
(Continued)

RESIDENTIAL SPACE HEATING

All space heating equipment to be served by the Company's system shall be single phase equipment approved by Underwriters' Laboratories, Inc., and the equipment and its installation shall conform to all National, State and Municipal Codes and to the following:

Individual resistance-type units for space heating larger than 1,650 watts shall be designed to operate at 240 or 208 volts, and no single unit shall be larger than 6 kW. Heating units of two kW or larger shall be controlled by approved thermostatic devices. When a group of heating units, with a total capacity of more than 6 kW, is to be actuated by a single thermostat, the controlling switch shall be so designed that not more than 6 kW can be switched on or off at any one time. Supplemental resistance-type heaters, that may be used with a heat exchanger, shall comply with the specifications listed above for such units.

SUMMER AND NON-SUMMER SEASONS

The summer season begins on June 1 of each year and ends on August 31 of each year. The non-summer season begins on September 1 of each year and ends on May 31 of each year.

MONTHLY CHARGE

The Monthly Charge is the sum of the Service Charge, the Energy Charge, and the Power Supply Adjustment at the following rates, and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), Schedule 95 (Adjustment for Municipal Exactions), and Schedule 98 (Residential and Small Farm Energy Credit).

	Summer	Non-summer
Service Charge, per month	$~~5.25~~10.00	$10.00
Energy Charge, per kWh		
0-~~3~~800 kWh	~~3.7647~~6.8993¢	6.0303¢
Over ~~3~~800 kWh	~~4.7063~~8.9691¢	7.5485¢
Power Supply Adjustment, per kWh	0.4116¢	0.4116¢

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 7
SMALL GENERAL SERVICE

AVAILABILITY

Service under this schedule is available at points on the Company's interconnected system within the State of Oregon where existing facilities of adequate capacity and desired phase and voltage are adjacent to the Premises to be served and additional investment by the Company for transmission, substation, or terminal facilities is not necessary to supply the desired service.

APPLICABILITY

Service under this schedule is applicable to Electric Service supplied to a Customer at one Point of Delivery and measured through one meter. This schedule is applicable to Customers whose metered energy usage is 3,000 kWh, or less, per Billing Period for ten or more Billing Periods during the most recent 12 consecutive Billing Periods~~ and whose Demand has not exceeded 30 kW more than once during the most recent 12 consecutive Billing Periods~~. When the Customer's Billing Period is less than 27 days or greater than ~~33~~ 36 days, the energy usage will be prorated to 30 days for purposes of determining eligibility under this schedule. Customers whose metered energy usage exceeds 3,000 kWh per Billing Period on an actual or prorated basis three times during the most recent 12 consecutive Billing Periods ~~or whose Demand has exceeded 30 kW more than once during the most recent 12 consecutive Billing Periods~~ are not eligible for service under this schedule and will be automatically transferred to the applicable schedule effective with the next Billing Period. New customers may initially be placed on this schedule based on estimated usage.

This schedule is also applicable to non-profit or tax supported ball fields, fairgrounds or rodeo grounds with high demands and intermittent use exceeding 3,000 kWh per month. This schedule is not applicable to standby service, service for resale, or shared service, or to individual or multiple family dwellings, or agricultural irrigation service after October 31, 2005.

TYPE OF SERVICE

The type of service provided under this schedule is single- and/or three-phase, at approximately 60 cycles and at the standard service voltage available at the Premises to be served.

SUMMER NON-SUMMER SEASONS

The summer season begins on June 1 of each year and ends on August 31 of each year. The non-summer season begins on September 1 of each year and ends on May 31 of each year.

MONTHLY CHARGE

The Monthly Charge is the sum of the Service Charge, the Energy Charge, and the Power Supply Adjustment at the following rates, and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), Schedule 95 (Adjustment for Municipal Exactions), and Schedule 98 (Residential and Small Farm Energy Credit).

	Summer	Non-Summer
Service Charge, per month		
Single-Phase Service	$~~6.55~~10.00	$~~6.55~~10.00
Three-Phase Service	~~13.10~~$20.00	~~13.10~~$20.00

SCHEDULE 7
SMALL GENERAL SERVICE
(Continued)

MONTHLY CHARGE (Continued)

	Summer	Non-Summer
Energy Charge, per kWh		
0-300 kWh	~~4.4549~~6.2725¢	~~4.4549~~6.2725¢
Over 300 kWh	~~4.9449~~9.1267¢	~~4.4549~~7.3135¢
Power Supply Adjustment, per kWh	0.4116¢	0.4116¢

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 9
LARGE GENERAL SERVICE

AVAILABILITY

Service under this schedule is available at points on the Company's interconnected system within the State of Oregon where existing facilities of adequate capacity and desired phase and voltage are adjacent to the premises to be served and additional investment by the Company for new transmission, substation, or terminal facilities is not necessary to supply the desired service.

APPLICABILITY

Service under this schedule is applicable to firm Electric Service supplied to a Customer where service at one Point of Delivery and measured through one meter.

This schedule is applicable to Customers whose energy usage exceeds 3,000 kWh per Billing Period for a minimum of three Billing Periods during the most recent 12 consecutive Billing Periods ~~or whose Demand has exceeded 30 kW more than once during the most recent 12 consecutive Billing Periods~~ and whose metered Demand per billing Period has not equaled or exceeded 1,000 kW more than twice during the most recent 12 consecutive Billing Periods. When the Customer's Billing Period is less than 27 days or greater than ~~33~~ 36 days, the metered energy usage will be prorated to 30 days for purposes of determining eligibility under this schedule. Customers whose metered energy usage does not exceed 3,000 kWh per Billing Period on an actual or prorated basis three or more times during the most recent 12 consecutive Billing Periods or whose metered demand equals or exceeds 1,000 kW per Billing Period three times or more during the most recent 12 consecutive Billing Periods are not eligible for service under this schedule and will be automatically transferred to the applicable schedule effective with the next Billing Period. New customers may initially be placed on this schedule based on estimated usage.

This schedule is not applicable to standby service, service for resale, or shared service, or to individual or multiple family dwellings, or to agricultural irrigation service after October 31, 2005.

TYPE OF SERVICE

The type of service provided under this schedule is single- and/or three-phase, at approximately 60 cycles and at the standard service voltage available at the Premises to be served.

BASIC LOAD CAPACITY

The Basic Load Capacity is the average of the two greatest non-zero monthly Billing Demands established during the 12-month period which includes and ends with the current Billing Period.

BILLING DEMAND

The Billing Demand is the average kW supplied during the 15-consecutive-minute period of maximum use during the Billing Period, adjusted for Power Factor.

ON-PEAK BILLING DEMAND

The On-Peak Billing Demand is the average kW supplied during the 15-minute period of maximum use during the Billing Period for the On-Peak time period.

SCHEDULE 9
LARGE GENERAL SERVICE
(Continued)

FACILITIES BEYOND THE POINT OF DELIVERY

At the option of the Company, transformers and other facilities installed beyond the Point of Delivery to provide Primary or Transmission Service may be owned, operated, and maintained by the Company in consideration of the Customer paying a Facilities Charge to the Company.

Company-owned Facilities Beyond the Point of Delivery will be set forth in a Distribution Facilities Investment Report provided to the Customer. As the company's investment in Facilities Beyond the Point of Delivery changes in order to provide the Customer's service requirements, the Company shall notify the Customer of the additions and/or deletions of facilities by forwarding to the Customer a revised Distribution Facilities Investment Report.

In the event the Customer requests the Company to remove or reinstall or change Company-owned Facilities Beyond the Point of Delivery, the Customer shall pay to the Company the "non-salvable cost" of such removal, reinstallation or change. Non-salvable cost as used herein is comprised of the total original costs of materials, labor and overheads of the facilities, less the difference between the salvable cost of material removed and removal labor cost including appropriate overhead costs.

POWER FACTOR

Where the Customer's Power Factor is less than ~~85~~ 90 percent, as determined by measurement under actual load conditions, the Company may adjust the kW measured to determine the Billing Demand by multiplying the measured kW by ~~85~~ 90 percent and dividing by the actual Power Factor. ~~Effective September 1, 2005, where the Customer's Power Factor is less than 90 percent, as determined by measurement under actual load conditions, the Company may adjust the kW measured to determine the Billing Demand by multiplying the measured kW by 90 percent and dividing by the actual Power Factor.~~

SUMMER AND NON-SUMMER SEASONS

The summer season begins on June 1 of each year and ends on August 31 of each year. The non-summer season begins on September 1 of each year and ends on May 31 of each year.

TIME PERIODS

The time periods are defined as follows. All times are stated in Mountain Time.

Summer Season

On-Peak	1:00 p.m. to 9:00 p.m. Monday through Friday, except holidays
Mid-Peak	7:00 a.m. to 1:00 p.m. and 9:00 p.m. to 11:00 p.m. Monday through Friday, except holidays, and 7:00 a.m. to 11:00 p.m. Saturday and Sunday, except holidays
Off-Peak	11:00 p.m. to 7:00 a.m. Monday through Sunday and all hours on holidays

Non-Summer Season

Mid-Peak	7:00 a.m. to 11:00 p.m., Monday through Saturday, except holidays
Off-Peak	11:00 p.m. to 7:00 a.m. Monday through Saturday and all hours on Sunday and holidays

The holidays observed by the Company are New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day. When New Year's Day, Independence Day, or Christmas Day falls on a Sunday, the Monday immediately following that Sunday will be considered a holiday.

SCHEDULE 9
LARGE GENERAL SERVICE
(Continued)

MONTHLY CHARGE

The Monthly Charge is the sum of the Service Charge, the Energy Charge, and the Power Supply Adjustment at the following rates, and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), Schedule 95 (Adjustment for Municipal Exactions), and Schedule 98 (Residential and Small Farm Energy Credit).

SECONDARY SERVICE	Summer	Non-Summer
Service Charge, per month		
Single Phase Service	$~~8~~11.50	$~~8~~11.50
Three Phase Service	$~~15.00~~20.25	$~~15.00~~20.25
Basic Charge, per kW of Basic Load Capacity	$0.~~38~~68	$0.~~38~~68
Demand Charge, per kW of Billing Demand	$~~4.51~~5.70	$4.12
Energy Charge, per kWh	~~3.2306~~4.4290¢	~~2.9232~~3.8684¢
Power Supply Adjustment, per kWh	0.4116¢	0.4116¢

Facilities Charge
None

PRIMARY SERVICE	Summer	Non-Summer
Service Charge, per month	$~~125~~215.00	$~~125~~215.00
Basic Charge, per kW of Basic Load Capacity	$~~0.78~~1.04	$~~0.78~~1.04
Demand Charge, per kW of Billing Demand	$~~4.26~~4.82~~1~~	$~~3.86~~4.45
On-Peak Demand Charge, per kW of On-Peak Billing Demand	$0.69	$0.69
Energy Charge, per kWh	~~2.2917¢~~	~~2.0646¢~~
On-Peak	4.2761	n/a
Mid-Peak	3.8874¢	3.4094¢
Off-Peak	3.6331¢	3.2470¢
Power Supply Adjustment	0.4116¢	0.4116¢

Facilities Charge
The Company's investment in Company-owned Facilities Beyond the Point of Delivery times 1.7 percent.

SCHEDULE 9
LARGE GENERAL SERVICE
(Continued)

TRANSMISSION SERVICE	Summer	Non-Summer
Service Charge, per month	$~~125~~215.00	$~~125~~215.00
Basic Charge, per kW of Basic Load Capacity	$0.~~41~~30	$0.~~41~~30
Demand Charge, per kW of Billing Demand	~~$4.12~~3.59	~~$3.74~~3.84
On-Peak Demand Charge, per kW of On-Peak Billing Demand	$0.69	$0.69
~~Energy Charge, per kWh~~	~~2.2406¢~~	~~2.0186¢~~
On-Peak	4.2042¢	n/a
Mid-Peak	3.8220¢	3.3536¢
Off-Peak	3.5720¢	3.1939¢
Power Supply Adjustment	0.4116¢	0.4116¢

Facilities Charge
The Company's investment in Company-owned Facilities Beyond the Point of Delivery times 1.7 percent.

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 15
DUSK TO DAWN CUSTOMER LIGHTING

AVAILABILITY

Service under this schedule is available to commercial institutions, industrial plants, and residential Customers presently served from the Company's interconnected system within the State of Oregon where existing overhead secondary distribution facilities of adequate capacity, phase and voltage are presently available adjacent to the Premises to be lighted.

APPLICABILITY

Service under this schedule is applicable to Electric Service provided for the outdoor dusk to dawn lighting of commercial, industrial and residential Customer grounds, yards, driveways and Premises by means of a Company-owned luminary, mounted on an existing Company pole with a support bracket and automatically controlled by a photoelectric relay. At the request of a Customer, but at the sole discretion of the Company, a luminary may be mounted on a Customer-owned support acceptable to the Company. The type and kind of fixtures and supports will be in accordance with the Company's specifications.

CHARACTER OF SERVICE

The facilities required for supplying service, including fixture, lamp, control relay, and support bracket for mounting on an existing Company pole with secondary service or, at the request of a Customer and at the Company's sole discretion, on a Customer-owned support acceptable to the Company, are supplied, installed, owned and maintained by the Company in accordance with the Company's standards and specifications. All necessary repairs and maintenance work, including lamp renewal, will be performed by the Company only during the regularly scheduled working hours of the Company, and the Company shall be allowed 72 hours~~,~~ following notification by the Customer, for replacing any burned out lamps. Lamps are energized each night from ~~one-half hour~~20 minutes after sunset until ~~one-half hour~~20 minutes before sunrise, thereby providing approximately 4,~~105~~ 059 hours of Premises lighting per year. The Company retains the right, but not the obligation, to terminate and remove service from a Customer-owned support at any time.

If the Customer requests that the Company install a Company-owned luminary on a ~~c~~Customer-owned support, the Customer through its request, agrees to permit the Company and its representatives reasonable access onto and across the Customer's property for the purposes of installing, maintaining and removing the luminary. In addition, the Customer voluntarily agrees to release the Company (including its directors, officers, employees, agents, parent company, affiliates, successors and assigns) from all liability, loss, claims or actions for injury, death, expenses (including, but not limited to, reasonable attorney fees and court costs) or damage to person or property resulting from the Company's installation, maintenance and removal of the luminary located on a Customer-owned support. The Customer also agrees to indemnify and hold harmless the Company from any liability, claim, loss, action or expense (including, but not limited to, reasonable attorney fees and court costs) asserted against or incurred by the Company for damages arising out of actions or inactions of the Customer and the Customer's employees, agents, representatives or others acting on their behalf.

NEW FACILITIES

Where facilities of the Company are not presently available for a lamp installation which will provide satisfactory lighting service for the Customer's Premises, the Company may install overhead or underground secondary service facilities, including secondary conductor, poles, anchors, etc., a distance not to exceed 300 feet to supply the desired service, all in accordance with the charges specified below.

SCHEDULE 15
DUSK TO DAWN CUSTOMER LIGHTING
(Continued)

MONTHLY CHARGE~~S~~

The Monthly Charge is the sum of the per Unit Charge and the Power Supply Adjustment at the following ~~rates~~charges, and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Exactions).

1. Monthly P~~p~~er U~~u~~nit C~~c~~harge on existing facilities:

AREA LIGHTING

High Pressure Sodium Vapor	Average Lumens	Monthly Base Rate	Power Supply Adjustment
100 Watt	8,550	$~~ 9.27~~62	$0.14
200 Watt	19,800	$15.~~03~~38	$0.28
400 Watt	45,000	$24.~~02~~37	$0.56

FLOOD LIGHTING

High Pressure Sodium Vapor	Average Lumens	Monthly Base Rate	Power Supply Adjustment
200 Watt	19,800	$18.~~31~~66	$0.28
400 Watt	45,000	$27.~~32~~67	$0.56
Metal Halide			
400 Watt	28,800	$30.~~58~~93	$0.56
1,000 Watt	88,000	~~$55.87~~56.22	$1.41

2. For New Facilities Installed Before August 8, 2005. The Monthly Charge for New Facilities installed, prior to August 8, 2005 such as overhead secondary conductor, poles, anchors, etc., shall be 1.75 percent of the estimated installed cost thereof.

3. For New Facilities Installed On or After August 8, 2005: The non-refundable charge for New Facilities to be installed, such as underground service, overhead secondary conductor, poles, anchors, etc., shall be equal to the work order cost.

PAYMENT

The monthly bill for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 19
LARGE POWER SERVICE

AVAILABILITY

Service under this schedule is available at points on the Company's interconnected system within the State of Oregon where existing facilities of adequate capacity and desired phase and voltage are available. If additional distribution facilities are required to supply the desired service, those facilities provided for under Rule H will be provided under the terms and conditions of that rule. To the extent that additional facilities not provided for under Rule H, including transmission and/or substation facilities, are required to provide the requested service, special arrangements will be made in a separate agreement between the Customer and the Company.

~~Effective August 8, 2005, all Uniform Large Power Service Agreements currently in effect will automatically be cancelled. Customers with loads equal to or in excess of 1,000 kW Demand at a single Point of Delivery will be required to enter into a Uniform Service Agreement as provided under Rule C.~~

APPLICABILITY

Service under this schedule is applicable to and mandatory for Customers who register a metered Demand of 1,000 kW or more per Billing Period for three or more Billing Periods during the most recent 12 consecutive Billing Periods. Customers whose initial usage, based on information provided by the Customer, is expected to be 1,000 kW or more per Billing Period for three or more Billing Periods during 12 consecutive Billing Periods may, at the Customer's request, take service under this schedule prior to meeting the metered demand criterion. This schedule will remain applicable until the Customer fails to register a metered demand of 1,000 kW or more per Billing Period for three or more Billing Periods during the most recent 12 consecutive Billing Periods.

Deliveries at more than one Point of Delivery or more than one voltage will be separately metered and billed. If the aggregate power requirement of a Customer who receives service at one or more Points of Delivery on the same Premises exceeds ~~25~~20,000 kW, the Customer is ineligible for service under this schedule and is required to make special contract arrangements with the Company.

This schedule is not applicable to service for resale, to shared or irrigation service, to standby or supplemental service, unless the Customer has entered into a Standby Service Agreement or other standby agreement with the Company, or to multi-family dwellings.

TYPE OF SERVICE

The Type of Service provided under this schedule is three-phase at approximately 60 cycles and at the standard service voltage available at the Premises to be served.

BASIC LOAD CAPACITY

The Basic Load Capacity is the average of the two greatest monthly Billing Demands established during the 12-month period which includes and ends with the current Billing Period, but not less than 1,000 kW.

BILLING DEMAND

The Billing Demand is the average kW supplied during the 15-consecutive-minute period of maximum use during the Billing Period, adjusted for Power Factor, but not less than 1,000 kW.

ON-PEAK BILLING DEMAND

The On-Peak Billing Demand is the average kW supplied during the 15-minute period of maximum use during the Billing Period for the On-Peak time period.

SCHEDULE 19
LARGE POWER SERVICE
(Continued)

TIME PERIODS

The time periods are defined as follows. All times are stated in Mountain Time.

Summer Season

On-Peak	1:00 p.m. to 9:00 p.m. Monday through Friday, except holidays
Mid-Peak	7:00 a.m. to 1:00 p.m. and 9:00 p.m. to 11:00 p.m. Monday through Friday, except holidays, and 7:00 a.m. to 11:00 p.m. Saturday and Sunday, ~~and~~ except holidays
Off-Peak	11:00 p.m. to 7:00 a.m. Monday through Sunday and all hours on holidays.~~all days~~

Non-Summer Season

Mid-Peak	7:00 a.m. to 11:00 p.m., Monday through Saturday, except holidays
Off-Peak	11:00 p.m. to 7:00 a.m. Monday through Saturday and all hours on Sunday and holidays

The holidays observed by the Company are New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day. When New Year's Day, Independence Day, or Christmas Day falls on a Sunday, the Monday immediately following that Sunday will be considered a holiday.

SUMMER AND NON-SUMMER SEASONS

The summer season begins on June 1 of each year and ends on August 31 of each year. The non-summer season begins on September 1 of each year and ends on May 31 of each year.

FACILITIES BEYOND THE POINT OF DELIVERY

At the option of the Company, transformers and other facilities installed beyond the Point of Delivery to provide Primary or Transmission Service may be owned, operated, and maintained by the Company in consideration of the Customer paying a Facilities Charge to the Company.

Company-owned Facilities Beyond the Point of Delivery will be set forth in a Distribution Facilities Investment Report provided to the Customer. As the Company's investment in Facilities Beyond the Point of Delivery changes in order to provide the Customer's service requirements, the Company shall notify the Customer of the additions and/or deletions of facilities by forwarding to the Customer a revised Distribution Facilities Investment Report.

In the event the Customer requests the Company to remove or reinstall or change Company-owned Facilities Beyond the Point of Delivery, the Customer shall pay to the Company the "non-salvable cost" of such removal, reinstallation or change. Non-salvable cost as used herein is comprised of the total original costs of materials, labor and overheads of the facilities, less the difference between the salvable cost of material removed and removal labor cost including appropriate overhead costs.

SCHEDULE 19
LARGE POWER SERVICE
(Continued)

POWER FACTOR ADJUSTMENT

Where the Customer's Power Factor is less than ~~85~~ 90 percent, as determined by measurement under actual load conditions, the Company may adjust the kW measured to determine the Billing Demand by multiplying the measured kW by ~~85~~ 90 percent and dividing by the actual Power Factor. ~~Effective September 1, 2005, where the Customer's Power Factor is less than 90 percent, as determined by measurement under actual load conditions, the Company may adjust the kW measured to determine the Billing Demand by multiplying the measured kW by 90 percent and dividing by the actual Power Factor.~~

TEMPORARY SUSPENSION

When a Customer has properly invoked Rule G, Temporary Suspension of Demand, the Basic Load Capacity, the Billing Demand, and the On-Peak Billing Demand shall be prorated based on the period of such suspension in accordance with Rule G. In the event the Customer's metered demand is less than 1,000 kW during the period of such suspension, the Basic Load Capacity and Billing Demand will be set equal to 1,000 kW for purposes of determining the Customer's monthly Minimum Charge.

MONTHLY CHARGE

The Monthly Charge is the sum of the Service Charge, the Energy Charge, and the Power Supply Adjustment at the following rates, and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), Schedule 95 (Adjustment for Municipal Exactions), and Schedule 98 (Residential and Small Farm Energy Credit).

SECONDARY SERVICE	Summer	Non-Summer
Service Charge, per month	$~~125~~215.00	$~~125~~215.00
Basic Charge, per kW of Basic Load Capacity	$0.~~38~~68	$0.~~38~~68
Demand Charge, per kW of Billing Demand	$45.01	$~~3.96~~4.12
On-Peak Demand Charge, per kW of On-Peak Billing Demand	$0.~~36~~69	n/a
Energy Charge, per kWh		
On-Peak	~~3.3657~~5.4191¢	n/a
Mid-Peak	~~3.1978~~4.1685¢	~~3.1187~~4.0061¢
Off-Peak	~~2.9805~~3.6248¢	~~2.7836~~3.5769¢
Power Supply Adjustment*, per kWh	0.4116¢	0.4116¢

* A Customer who prepays the Power Supply Adjustment amount pursuant to ORS 757.259(11) shall not be subject to the Power Supply Adjustment rates.

Facilities Charge
None

SCHEDULE 19
LARGE POWER SERVICE
(Continued)

MONTHLY CHARGE (Continued)

PRIMARY SERVICE	Summer	Non-Summer
Service Charge, per month	$~~125~~215.00	$~~125~~215.00
Basic Charge, per kW of Basic Load Capacity	$~~0.78~~1.04	$~~0.78~~1.04
Demand Charge, per kW of Billing Demand	$~~3.90~~4.82	$~~3.86~~4.45
On-Peak Demand Charge, per kW of On-Peak Billing Demand	$0.~~36~~69	n/a
Energy Charge, per kWh		
On-Peak	~~2.4567~~4.1215¢	n/a
Mid-Peak	~~2.2175~~3.1704¢	~~2.0530~~2.9668¢
Off-Peak	~~2.0667~~2.7569¢	~~1.9587~~2.6489¢
Power Supply Adjustment*, per kWh	0.4116¢	0.4116¢

* A Customer who prepays the Power Supply Adjustment amount pursuant to ORS 757.259(11) shall not be subject to the Power Supply Adjustment rates.

Facilities Charge
The Company's investment in Company-owned Facilities Beyond the Point of Delivery times 1.7 percent.

SCHEDULE 19
LARGE POWER SERVICE
(Continued)

MONTHLY CHARGE (Continued)

TRANSMISSION SERVICE	Summer	Non-Summer
Service Charge, per month	$~~125~~215.00	$~~125~~215.00
Basic Charge, per kW of Basic Load Capacity	$0.~~41~~30	$0.~~41~~30
Demand Charge, per kW of Billing Demand	$~~3.52~~3.59	$~~3.76~~3.84
On-Peak Demand Charge, per kW of On-Peak Demand	$0.~~36~~69	n/a
Energy Charge, per kWh		
On-Peak	~~2.4131~~3.8928¢	n/a
Mid-Peak	~~2.1780~~2.9941¢	~~2.0092~~2.7946¢
Off-Peak	~~2.0300~~2.6036¢	~~1.9169~~2.4952¢
Power Supply Adjustment*, per kWh	0.4116¢	0.4116¢

* A Customer who prepays the Power Supply Adjustment amount pursuant to ORS 757.259(11) shall not be subject to the Power Supply Adjustment rates.

Facilities Charge
The Company's investment in Company-owned Facilities Beyond the Point of Delivery times 1.7 percent.

PAYMENT

The monthly bill for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 23
IRRIGATION PEAK REWARDS PROGRAM
(OPTIONAL)

PURPOSE

The Irrigation Peak Rewards Program (the Program) is an optional, supplemental service that permits participating agricultural irrigation Customers taking service under Schedule 24 to allow the Company to turn off specific irrigation pumps with the use of one or more Load Control Devices. In exchange for allowing the Company to turn off specified irrigation pumps, participating Customers will receive a financial incentive in the form of a Bill Credit applied to the monthly bills for usage that occurs during the calendar months of June and July for each metered service point (Metered Service Point) enrolled in the Program.

AVAILABILITY

Service under this schedule is available on an optional basis to Customers with a Metered Service Point or Points receiving service under Schedule 24 where the Metered Service Point serves a water pumping or water delivery system used to irrigate agricultural crops or pasturage.

The Company shall have the right to select and reject Program participants at its sole discretion based on criteria the Company considers necessary to ensure the effective operation of the Program. Selection criteria may include, but will not be limited to, Billing Demand, location, pump horsepower, pumping system configuration, or electric system configuration. Past participation does not ensure selection into the Program in future years. Participation may be limited based upon the availability of Program equipment and funding.

Each eligible Customer who chooses to take service under this optional schedule is required to enter into a Uniform Irrigation Peak Rewards Service Application/Agreement (Agreement) with the Company prior to being served under this schedule. The Agreement will grant the Company or its representative permission, on reasonable notice, to enter the Customer's property to install one or more Load Control Devices on the electrical panel servicing the irrigation equipment associated with the Metered Service Points that are enrolled in this Program and to allow the Company or its representative reasonable access to the Load Control Device(s) following the installation. By entering into the Agreement, each Customer also agrees to not increase for the sole purpose of participating in the Program the capacity, horsepower (HP) or size of the irrigation system served by the Company.

PROGRAM DESCRIPTION

Service under this optional, supplementary Program permits the Company to turn off specified irrigation pumps for a limited number of hours during the period of June 15 through July 31 (Program Season). The Company will utilize either dispatchable or timer-based Load Control Devices to turn off specific irrigation pumps during load control events. In limited applications, a select group of eligible Customers will be permitted to manually interrupt electric service to participating irrigation pumps during load control events (See Dispatchable Option 3). In exchange for allowing the Company to interrupt service to specified irrigation pumps, participating Customers will receive a financial incentive in the form of a Bill Credit applied to the monthly bills for usage that occurs during the calendar months of June and July for each Metered Service Point enrolled in the Program.

SCHEDULE 23
IRRIGATION PEAK REWARDS
PROGRAM
(OPTIONAL)
(Continued)

DEFINITIONS

Bill Credit. The Bill Credit is the sum of the Demand Credit and the Energy Credit applied to the Customer's monthly bills for usage that occurs during the calendar months of June and July of each year. This amount may be prorated for the number of days during the months of June and July that fall in the Customer's billing cycle.

Demand Credit. The Demand Credit is a demand-based financial incentive provided in the form of a credit on the monthly bill for the Metered Service Point enrolled in the Program. The monthly Demand Credit is calculated by multiplying the Program kW by the demand-related incentive amount for the Interruption Option selected by the Customer. The Demand Credit will be included on the Customer's monthly bills for usage that occurs during the calendar months of June and July of each year. This amount may be prorated for the number of days during the months of June and July that fall in the Customer's billing cycle.

Energy Credit. The Energy Credit is an energy-based financial incentive provided in the form of a credit on the monthly bill for the Metered Service Point enrolled in the Program. The monthly Energy Credit is calculated by multiplying the Program kWh by the energy-related incentive amount for the Interruption Option selected by the Customer. The Energy Credit will be included on the Customer's monthly bills for usage that occurs during the calendar months of June and July of each year. This amount may be prorated for the number of days during the months of June and July that fall in the Customer's billing cycle.

Load Control Device. Load Control Device refers to any technology, device or system utilized under the Program to enable the Company to initiate the load control event.

Notification of Program Acceptance. An interested Customer must sign and return to the Company an Agreement specifying the Metered Service Point(s) to be included in the Program. If a Customer is selected for participation in the Program, a notification of acceptance into the Program will be mailed to participants, which will include a listing of the Metered Service Point(s) that have been enrolled.

Program kW. The Program kW is the demand amount, as measured at the Customer's meter in kilowatts (kW), that is multiplied by the applicable incentive amount to determine the Demand Credit under each Interruption Option.

Program kWh. The Program kWh is the energy amount, as measured at the Customer's meter in kilowatt-hours (kWh), that is multiplied by the applicable incentive amount to determine the Energy Credit under each Interruption Option.

SCHEDULE 23
IRRIGATION PEAK REWARDS
PROGRAM
(OPTIONAL)
(Continued)

INTERRUPTION OPTIONS

Dispatchable Option

Under the Dispatchable Option, the Company will dispatch remotely service interruptions to specified irrigation pumps any weekday during the Program Season between the hours of 2:00 P.M. and 8:00 P.M. Mountain Daylight Time (MDT), excluding July 4. Service interruptions may last up to 4 hours per day and will not exceed 15 hours per calendar week and 60 hours per Program Season. The Company will provide to participating customers notice of pending service interruption by 4:00 P.M. MDT on the day prior to each load control event. The Company will provide subsequent notice of a pending service interruption 30 minutes notice prior to the start of all load control events and once again prior to the end of all load control events. If prior notice of a pending load control event has been sent, the Company may choose to revoke the load control event and will provide notice to Customers by 1:30 P.M. MDT on the day of the scheduled load control event. The Company will provide notice of a load control event via the following communication technologies: telephone, e-mail and/or text message.

Customers who elect to participate in the Program under a Dispatchable Option may be eligible for one of the following Dispatchable Options:

Option 1. A dispatchable one-way communication Load Control Device will be connected to the electrical panel(s) serving the irrigation pumps associated with the Metered Service Points enrolled in the Program. The Load Control Device utilized under this Dispatchable Option will provide the Company the ability to send a signal that will interrupt or not allow the associated irrigation pumps to operate during dispatched load control events. This option requires that all pumps at the Metered Service Point be controlled.

Under Dispatchable Option 1, the Program kW will be based upon the monthly Billing Demand, as measured in kW, for the associated Billing Period. The Program kWh under this option will be based upon the monthly energy usage, as measured in kWh, for the associated Billing Period.

Customers selecting Dispatchable Option 1 may opt-out of a load control event up to five times per season any time prior to or during a load control event. Each time a customer chooses to opt-out of a load control event a fee of $0.005 per kWh will be assessed based upon the current month's Program kWh. This amount may be prorated for the number of days during the months of June and July that fall in the Customer's billing cycle.

SCHEDULE 23
IRRIGATION PEAK REWARDS
PROGRAM
(OPTIONAL)
(Continued)

INTERRUPTION OPTIONS (Continued)

Option 2. A dispatchable Load Control Device capable of two-way communication will be connected to the electrical panel(s) servicing the irrigation pumps associated with the Metered Service Points enrolled in this Program. The Load Control Device utilized under this Dispatchable Option will provide t he Company and the Customer remote control and monitoring of the associated irrigation pumps. Under this option, the Company will use this technology to send a signal that will interrupt or not allow the irrigation pumps to operate during dispatched load control events. This option requires that all pumps at the Metered Service Point be controlled.

Under Dispatchable Option 2, the Program kW will be based upon the monthly Billing Demand, as measured in kW, for the associated Billing Period. The Program kWh under this option will be based upon the monthly energy usage, as measured in kWh, for the associated Billing Period.

Customer selecting Dispatchable Option 2 may opt-out of a load control event up to five times per season any time prior to or during a load control event. Each time a customer chooses to opt-out of a load control event a fee of $0.005 per kWh will be assessed based upon the current month's Program kWh. This amount may be prorated for the number of days during the months of June and July that fall in the Customer's billing cycle.

Option 3. Metered Service Points with interval metering having more than one pump and at least 1,000 cumulative HP are eligible for Dispatchable Option 3. Under this Dispatchable Option, eligible Customers can choose to either 1) have service interrupted using a dispatchable two-way communication Load Control Device, as in Dispatchable Option 2, or 2) manually interrupt electric service to participating irrigation pumps during load control events. This option provides Customers with the flexibility to choose which irrigation pumps will be interrupted during each dispatched load control event.

Under Dispatchable Option 3, the Program kW will be based upon the monthly Billing Demand minus the average demand, as measured in kW over 15 minute intervals, during each load control event initiated during a Billing Period. The Program kWh under this option will be based upon a calculated value, as measured in kWh. The Program kWh will be calculated separately for each Billing Period by multiplying the monthly Program kW by the ratio of the monthly energy usage to the Billing Demand for the associated Billing Period.

Timer Option

Under the Timer Option, the Company or its representative will install a timer-based Load Control Device on the Customer's electrical panel controlling the irrigation pumps at the Metered Service Point enrolled in the Program. The Company or its representative will set the timer or timers to interrupt specified irrigation pumps on a designated weekday or designated weekdays selected by the Customer. The Company will set each timer to interrupt service during the weekday hours of 4:00 P.M

SCHEDULE 23
IRRIGATION PEAK REWARDS
PROGRAM
(OPTIONAL)
(Continued)

INTERRUPTION OPTIONS (Continued)

to 8:00 P.M. MDT. Each Metered Service Point's timer will be set to interrupt service on one, two, or three regularly scheduled weekdays per week for each week during the Program Season. The Company retains the sole right to select the load reduction weekday(s) for each Metered Service Point.

Changes to the Interruption Schedule. A Customer who elects to reduce the number of days of weekly interruption of a Metered Service Point on or after June 15 of each calendar year shall pay the Company the sum of $100.00, which sum will be included on the Customer's monthly bill following the implementation of the requested change. The Customer's Bill Credit shall be prorated based upon the number of days in that month the Customer participated under each interruption schedule. The Company will not accept any requests to increase the number of days of weekly interruption on or after June 15 of each calendar year.

INCENTIVE STRUCTURE

Dispatchable Interruption Option		
Dispatchable Option	Demand Credit ($ per Program kW)	Energy Credit ($ per Program kWh)
1	$4.65	$0.031
2	$4.65	$0.031
3	$4.65	$0.031
Timer Interruption Option		
Timer Option	Demand Credit ($ per Program kW)	Energy Credit ($ per Program kWh)
One Weekday	$3.15	$0.000
Two Weekdays	$4.65	$0.002
Three Weekdays	$4.65	$0.007

INSTALLATION FEES

An Installation Fee may be applicable depending upon the size, as measured in horsepower, of the irrigation system associated with a participating Metered Service Point. The purpose of the Installation Fee is to offset a portion of the installation costs associated with Metered Service Points having smaller load reduction capabilities. The Installation Fee is non-refundable except when a Customer elects for Early Termination of the Program. An Installation Fee will apply according to the following table:

SCHEDULE 23
IRRIGATION PEAK REWARDS
PROGRAM
(OPTIONAL)
(Continued)

INSTALLATION FEES (Continued)

Horsepower (HP)	Dispatchable Option			Timer Option
	1	2	3 *	
Less than 30 HP	$500	$1,000	N/A	$500
From 30 to 49 HP	$0	$500	N/A	$350
From 50 to 74 HP	$0	$0	N/A	$350
From 75 to 99 HP	$0	$0	N/A	$250
Greater than 99 HP	$0	$0	N/A	$0

Note: (*) An installation Fee will not be assessed under Dispatchable Option 3.

TERM OF AGREEMENT AND TERMINATION

The term of the Agreement, as it applies to each Metered Service Point accepted for participation, shall commence on the date the Agreement is signed by both the Customer and the Company and shall automatically renew on March 15 of each calendar year unless notice of termination is given by either party to the other prior to the annual renewal date or unless otherwise terminated as follows:

1. A Customer may terminate the participation of a Metered Service Point without penalty by notifying the Company or its representative before the Load Control Device(s) has been installed on the Metered Service Point (Early Termination).

2. A Customer who terminates the participation of a Metered Service Point anytime between June 15 and July 31 of each calendar year and who does not satisfy the provisions of item 1 above, shall pay the Company a Termination Fee, which sum will be included on the Customer's monthly bill following termination of participation. The Customer's Bill Credit shall be prorated for the number of days in that month the Customer satisfactorily participated in the Program. In the first year that a Metered Service Point becomes enrolled in the Program, a Termination Fee will also be assessed whenever a Customer does not satisfy the provisions of item 1 and requests to terminate participation of the newly enrolled Metered Service Point anytime prior to July 31. Upon terminating participation of a Metered Service Point under the provisions of item 2, the Customer may not re-enroll the Metered Service Point into the Program until the following calendar year.

Termination Fees:

Dispatchable Option $500.00 per Metered Service Point terminated under item 2
Timer Option $100.00 per Metered Service Point terminated under item 2

3. If there is evidence of alteration, tampering, or otherwise interfering with the Company's ability to initiate a load control event at a Metered Service Point, the Agreement as it applies to that Metered Service Point will be automatically terminated. In addition, the Customer will be subject to each of the following:

SCHEDULE 23
IRRIGATION PEAK REWARDS
PROGRAM
(OPTIONAL)
(Continued)

TERM OF AGREEMENT AND TERMINATION (Continued)

a. The Customer will be required to reimburse the Company for the cost of replacement or repair of the Load Control Device(s), including labor and other related costs.

b. An applicable Termination Fee, as provided under item 2, will be applied to the Customer's monthly bill following the termination of participation.

c. The Company will reverse any and all Demand Credits and/or Energy Credits applied to the Customer's monthly bill(s) for the Metered Service Point as a result of the Customer's participation in the Program during the current year.

Note: A service disconnection for any reason does not terminate the Agreement.

SPECIAL CONDITIONS

The provisions of this schedule do not apply for any time period that the Company utilizes a Load Control Device installed under this Program to interrupt the Customer's load for a system emergency or any other time that a Customer's service is interrupted by events outside the control of the Company. The provisions of this schedule will not affect the calculation or rate of the regular Service, Energy or Demand Charges associated with a Customer's standard service schedule.

Mass memory meters may be installed on a select number of Metered Service Points for Program monitoring and evaluation purposes. The sample of Metered Service Points selected for monitoring and evaluation will be chosen at the Company's sole discretion.

SCHEDULE 23
IRRIGATION PEAK REWARDS
PROGRAM
(OPTIONAL)
(Continued)

Uniform Irrigation Peak Rewards Service
Application/Agreement

THIS AGREEMENT Made this ____ day of ______________________________, ______ between ____ hereinafter called Customer, whose billing address is ____, and IDAHO POWER COMPANY, a corporation with its principal office located at 1221 West Idaho Street, Boise, Idaho, hereinafter called Company. This Agreement shall automatically renew on March 15 of each calendar year unless notice of termination is given by either party to the other prior to the annual renewal date. This Agreement is for the Metered Service Point(s) identified on the attached worksheet (Worksheet):

The Customer designates the following person as the Customer's authorized contact:

Authorized Contact: ____
Phone: ________________________________ Cell Phone: ________________________________
Fax: ____
Email: ____

NOW, THEREFORE, The Parties agree as follows:

1. The Uniform Irrigation Peak Rewards Service Application/Agreement must be signed by the Customer and the Customer must be the person who is responsible for paying bills for retail electric service provided by the Company at the Metered Service Point(s) identified on the Worksheet.

2. The Customer understands that the information concerning the Metered Service Point(s) on the Worksheet is based on the best information currently available to the Company. The Bill Credit amounts are estimates based on the previous year's billing history for the Metered Service Point(s) specified on the Worksheet. Customers without sufficient billing history will be provided an estimated Bill Credit based on the stated cumulative horsepower at the Metered Service Point. The Bill Credit estimates are provided for illustration purposes. The Customer agrees to specify which Metered Service Point(s) listed on the Worksheet the Customer wishes to enroll in the Program and the Interruption Option selected for each specified Metered Service Point.

3. From time to time during the term of this Agreement and with prior reasonable notice from the Company, the Customer shall permit the Company or its representative to enter the Customer's property on which the enrolled Metered Service Point(s) are located to permit the Company or its representative to install, service, maintain and/or remove Load Control Device(s) on the electrical panel that services the Customer's irrigation pumps. The Load Control Device(s) may remain in place on the Customer's property upon termination of the Agreement unless the Customer specifically requests removal.

SCHEDULE 23
IRRIGATION PEAK REWARDS
PROGRAM
(OPTIONAL)
(Continued)

Uniform Irrigation Peak Rewards Service
Application/Agreement
(Continued)

4. The Customer understands and acknowledges that by participating in the Program, the Company shall, at its sole discretion, have the ability to interrupt the specified irrigation pumps at the Metered Service Point(s) enrolled in the Program according to the provisions of the Interruption Option selected. The Company retains the sole right to determine the criteria under which a load control event is scheduled for each Metered Service Point. The Customer also understands and acknowledges that if a Metered Service Point provides electricity to more than one irrigation pump, each pump will be scheduled for service interruption simultaneously, excluding Metered Service Points participating in the Program under Dispatchable Option 3.

5. The Customer may be required to pay an Installation Fee when a Load Control Device is installed on an eligible Metered Service Point providing electric service to irrigation pumps with less than 100 cumulative horsepower. The Installation Fee is non-refundable except when a Customer elects for Early Termination of the Program.

6. For the Customer's satisfactory participation in the Program, the Company agrees to pay the Customer the Demand Credit and/or Energy Credit corresponding to the Interruption Option selected by the Customer. The Bill Credit included on the Worksheet is based upon the billing history for the Metered Service Point(s) specified on the Worksheet, for the months of June, and July of the prior year. The Bill Credit will be paid in the form of a credit on the Customer's monthly bill. The Demand Credit may be prorated for the months of June and July depending on the Customer's billing cycle.

7. If the Customer terminates this Agreement anytime between June 15 and July 31 of the current calendar year while the Metered Service Point(s) are still connected for service and has not elected Early Termination of the Program, the Customer agrees to pay the Company the applicable Termination Fee, which sum will be included on the Customer's monthly bill. The Customer's Bill Credit for the month of termination shall be prorated for the number of days in that month that the Customer is a participant in good standing in the Program. In the first year that a Metered Service Point becomes enrolled in the Program, a Termination Fee will also be assessed whenever the Customer does not elect for Early Termination and requests to terminate the participation of the newly enrolled Metered Service Point anytime prior to July 31. Upon terminating participation of a Metered Service the Customer may not re-enroll that Metered Service Point into the Program until the following calendar year.

8. Under the Timer Option, whenever the Customer elects to change Options to reduce the number of days of weekly interruption of a Metered Service Point on or after June 15 of each calendar year, the Customer shall pay the Company the sum of $100.00, which sum will be included on the Customer's monthly bill following the implementation of the requested change. The Customer's Bill Credit shall be prorated based upon the number of days in that month the Customer participated under each interruption schedule. The Company will not accept any requests to increase the number of days of weekly interruption on or after June 15 of each calendar year.

SCHEDULE 23
IRRIGATION PEAK REWARDS
PROGRAM
(OPTIONAL)
(Continued)

Uniform Irrigation Peak Rewards Service
Application/Agreement
(Continued)

9. If there is evidence of alteration, tampering, or otherwise interfering with the Company's ability to initiate a load control event at a Metered Service Point(s), the Agreement as it applies to that Metered Service Point will be automatically terminated. The Customer will also be required to reimburse the Company for all costs of replacement or repair of the Load Control Device(s), including labor and other related costs, pay the Company the applicable Termination Fee which sum will be included on the Customer's monthly bill and the Company will reverse any Demand Credits applied to the Customer's monthly bill(s) for the Metered Service Point as a result of the Customer's participation in the Program during the current year.

10. The Company's Schedule 23, any revisions to that schedule and/or any successor schedule are to be considered part of this Agreement.

11. This Agreement and the rates, terms and conditions of service set forth or incorporated herein and the respective rights and obligations of the Parties hereunder shall be subject to valid laws and to the regulatory authority and orders, rules and regulations of the Oregon Public Utility Commission and such other administrative bodies having jurisdiction.

12. Nothing herein shall be construed as limiting the Idaho Public Utilities Commission from changing any terms, rates, charges, classification of service or any rules, regulations or conditions relating to service under this Agreement, or construed as affecting the right of the Company or the Customer to unilaterally make application to the Commission for any such change.

13. In any action at law or equity under this Agreement and upon which judgment is rendered, the prevailing Party, as part of such judgment, shall be entitled to recover all costs, including reasonable attorneys fees, incurred on account of such action.

14. The Company retains the sole right to select and reject the participants to receive service under Schedule 23. The Company retains the sole right for its employees and its representatives to install or not install Load Control Devices on the Customer's electrical panel at the time of installation depending on, but not limited to, safety, reliability, or other issues that may not be in the best interest of the Company, its employees or its representatives.

15. Under no circumstances shall the Company or any subsidiary, affiliates or parent Company be held liable to the Customer or any other party for damages or for any loss, whether direct, indirect, consequential, incidental, punitive or exemplary resulting from the Program or from the Customer's participation in the Program. The Customer assumes all liability and agrees to indemnify and hold harmless the Company and its subsidiaries, affiliates and parent company for personal injury, including death, and for property damage caused by the Customer's decision to participate in the Program and to reduce loads.

SCHEDULE 23
IRRIGATION PEAK REWARDS
PROGRAM
(OPTIONAL)
(Continued)

Uniform Irrigation Peak Rewards Service
Application/Agreement
(Continued)

The Company makes no warranty of merchantability or fitness for a particular purpose with respect to the Load Control Device(s) and any and all implied warranties are disclaimed.

(Appropriate Signatures)

SCHEDULE 24
AGRICULTURAL IRRIGATION SERVICE

AVAILABILITY

Service under this schedule is available at points on the Company's interconnected system within the State of Oregon for loads up to 25,000 kW where existing facilities of adequate capacity and desired phase and voltage are adjacent to the Premises to be served, and additional investment by the Company for new transmission, substation or terminal facilities is not necessary to supply the desired service. If the aggregate power requirement of a Customer who receives service at one or more Points of Delivery on the same Premises exceeds 25,000 kW, special contract arrangements will be required.

APPLICABILITY

Service under this schedule is applicable to power and energy supplied to agricultural use customers operating water pumping or water delivery systems used to irrigate agricultural crops or pasturage at one Point of Delivery and through one meter. Water pumping or water delivery systems include, but are not limited to, irrigation pumps, pivots, fertilizer pumps, drainage pumps, linears, and wheel lines.

~~Customers currently receiving service under this schedule who do not meet the eligibility criteria for service under this schedule may continue to receive service under this schedule through October 31, 2005. On November 1, 2005 all customers for whom this schedule is not applicable will be transferred to the appropriate general service schedule.~~

TYPE OF SERVICE

The type of service provided under this schedule is single- and/or three-phase, alternating current, at approximately 60 cycles and at the standard voltage available at the Premises to be served.

SERVICE CONNECTION AND DISCONNECTION

The Company will routinely keep service connected throughout the calendar year unless the Customer requests service be disconnected. Customer requested service disconnections will be made at no charge during the Company's normal business hours. The Company's termination practices as specified under Rule F will continue to apply with the exception that service terminations will not be made during the Irrigation Season.

Service Connection Charge. A Service Connection Charge as specified in Schedule 66 will be assessed when service is reconnected.

Service Establishment Charge. A Service Establishment Charge as specified in Schedule 66 will be assessed when service that is currently energized at the Point of Delivery is established for the Customer.

SEASONAL DEFINITION

The Irrigation Season will begin with the Customer's meter reading for the May Billing Period and end with the Customer's meter reading for the September Billing Period. The beginning cycles of a Billing Period may actually be based on meter readings taken not more than 7 days prior to the start of the corresponding calendar month.

SCHEDULE 24
AGRICULTURAL IRRIGATION SERVICE
(Continued)

BILLING DEMAND

The Billing Demand is the average kW supplied during the 15-consecutive-minute period of maximum use during the Billing Period, adjusted for Power Factor; PROVIDED That at the Company's option the Billing Demand of a single motor installation of 5 horsepower and less may be equal to the number of horsepower but not less than ~~one~~1 kW. Metered power demands in kW which exceed 130 percent of the connected horsepower served through one Point of Delivery will not be used for billing purposes unless and until verified by field test in the presence of the Customer to be the result of normal pumping operations. If a demand in excess of 130 percent of the connected horsepower is the result of abnormal conditions existing on the Company's interconnected system or the Customer's system, including accidental equipment failure or electrical supply interruption which results in the temporary separation of the Company's and the Customer's system, the Billing Demand shall be 130 percent of the connected horsepower. ~~The Customer~~Customers may appeal the Company's billing decision to the Oregon Public Utility Commission in cases of dispute.

FACILITIES BEYOND THE POINT OF DELIVERY

At the option of the Company, transformers and other facilities installed beyond the Point of Delivery to provide Transmission Service may be owned, operated, and maintained by the Company in consideration of the Customer paying a Facilities Charge to the Company.

Company-owned Facilities Beyond the Point of Delivery will be set forth in a Distribution Facilities Investment Report provided to the Customer. As the Company's investment in Facilities Beyond the Point of Delivery changes in order to provide the Customer's service requirements, the Company shall notify the Customer of the additions and/or deletions of facilities by forwarding to the Customer a revised Distribution Facilities Investment Report.

In the event the Customer requests the Company to remove or reinstall or change Company-owned Facilities Beyond the Point of Delivery, the Customer shall pay to the Company the "non-salvable cost" of such removal, reinstallation or change. Non-salvable cost as used herein is comprised of the total original costs of materials, labor and overheads of the facilities, less the difference between the salvable cost of material removed and removal labor cost including appropriate overhead costs.

POWER FACTOR ADJUSTMENT

~~Where the Customer's Power Factor is less than 85 percent, as determined by measurement under actual load conditions, the Company may adjust the kW measured to determine the Billing Demand by multiplying the measured kW by 85 percent and dividing by the actual Power Factor. Effective September 1, 2005, where~~ Where the Customer's Power Factor is less than 90 percent, as determined by measurement under actual load conditions, the Company may adjust the kW measured to determine the Billing Demand by multiplying the measured kW by 90 percent and dividing by the actual Power Factor.

SCHEDULE 24
AGRICULTURAL IRRIGATION SERVICE
(Continued)

MONTHLY CHARGE

The Monthly Charge is the sum of the ~~Service Charge, the Energy Charge, and the Power Supply Adjustment at the~~ following ~~rates~~charges, and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), Schedule 95 (Adjustment for Municipal Exactions), and Schedule 98 (Residential and Small Farm Energy Credit).

SECONDARY SERVICE	In-Season	Out-of-Season
Service Charge, per month	$15.00	$3.00
Demand Charge, per kW of Billing Demand	$~~4.55~~7.20	$~~0.80~~0.00
Energy Charge~~, per kWh2.8375¢~~		
In Season		
First 164 kWh per kW of Demand	5.2513¢	n.a.
All Other kWh	5.0977¢	n.a.
Out-of-Season		
All kWh	n.a.	5.5152¢
Power Supply Adjustment, per kWh	0.4116¢	0.4116¢

Facilities Charge
None

TRANSMISSION SERVICE	In-Season	Out-of-Season
Service Charge, per month	$~~102~~128.00	$3.00
Demand Charge, per kW of Billing Demand	$~~4.30~~6.80	$0.~~76~~00
Energy Charge~~, per kWh~~	~~2.6969¢~~	~~2.6969¢~~
In Season		
First 164 kWh per kW of Demand	5.0453¢	n.a.
All Other kWh	4.8977¢	n.a.
Out-of-Season		
All kWh	n.a.	5.2989¢
Power Supply Adjustment, per kWh	0.4116¢	0.4116¢

Facilities Charge
The Company's investment in Company-owned Facilities Beyond the Point of Delivery times 1.7 percent.

SCHEDULE 24
AGRICULTURAL IRRIGATION SERVICE
(Continued)

PAYMENT

All monthly billings for Electric Service supplied hereunder are payable upon receipt, and become past due 15 days from the date on which rendered.

Deposit. A deposit payment for irrigation Customers is required under the following conditions:

1. Existing Customers.

a. Tier 1 Deposit. Customers who have two or more reminder notices for nonpayment of Electric Service during a 12-month period, or who have had service terminated for non-payment, or were required to pay a Tier 2 Deposit for the previous Irrigation Season, will be required to pay a Tier 1 Deposit, or provide a guarantee of payment from a bank or financial institution acceptable to the Company. A Tier 1 Deposit does not apply to Customers who have an outstanding balance on December 31 of over $1,000.00 (See Tier 2 Deposit). A reminder notice is issued approximately 45 days after the bill issue date if the balance owing for Electric Service totals $100 or more. The deposit for a specific installation is computed as follows:

(1) Monthly Billing Demand is determined by multiplying 80 percent times the connected horsepower.

(2) Monthly Energy (billing kWh) is determined by multiplying 50 percent times 720 hours times the Monthly Billing Demand.

(3) The Monthly Billing Demand and the Monthly Energy are multiplied by the current In-Season rates and added to the Irrigation In-Season Service Charge to determine the estimated monthly bill.

(4) The estimated monthly bill is multiplied by a factor of one and one-half (1.5).

b. Tier 2 Deposit. Customers who have an outstanding balance greater than $1,000.00 on December 31 will be required to pay a Tier 2 Deposit. A Tier 2 Deposit will also be required from Customers who have had an unpaid past due balance greater than $1,000 on December 31 during any of the previous 4 years and who have not subsequently had active service. A Tier 2 Deposit may be satisfied by a guarantee of payment from a bank or financial institution acceptable to the Company. The deposit for a specific installation is computed as follows:

(1) Monthly Billing Demand is determined by multiplying 80 percent times the connected horsepower.

(2) Monthly Energy (billing kWh) is determined by multiplying 50 percent times 720 hours times the Monthly Billing Demand.

(3) The Monthly Billing Demand and the Monthly Energy are multiplied by the current In-Season rates and added to the Irrigation In-Season ~~Customer~~Service Charge to determine the estimated monthly bill.

(4) The estimated monthly bill is multiplied by a factor of four (4)

SCHEDULE 24
AGRICULTURAL IRRIGATION SERVICE
(Continued)

2. New Customer. A deposit may be required for a new Customer at the Company's discretion. The deposit for a specific installation will be computed using the same methodology as outlined for existing Customers requiring a Tier 1 Deposit.

3. Bankruptcy or Receivership. An adequate assurance of payment as agreed to by the ~~utility~~Company or as may be ordered by a court of competent jurisdiction or the OPUC, shall be required from any Customer for whom an order for relief has been entered under the federal bankruptcy laws, or for whom a receiver has been appointed in a court proceeding. The maximum amount required for each season shall not exceed a payment equal to a deposit. For each irrigation season, an adequate assurance of payment shall be required as agreed to by the ~~utility~~Company, or as may be ordered by a court of competent jurisdiction, or the OPUC. This requirement shall continue from the date of the order for relief in bankruptcy, or the ~~court's order~~court appointing a receiver, until the ~~debtor's~~debtor's discharge in bankruptcy or the dismissal of the court proceeding. A Customer who has been discharged from bankruptcy or whose receivership proceeding has been terminated will be required to pay a Tier 2 Deposit at the start of the following season to the extent required by the payment provisions listed under ~~the other~~"Payment" section 1(b) above.

APPLICATION OF DEPOSIT/INTEREST

Interest will be computed by the Company on irrigation deposits required under this schedule at the annual percentage rate determined by the Commission under Oregon Administrative Rules 860–021–0210. The irrigation deposit, with accrued interest, will be applied to the Customer's account as follows:

Tier 1 Deposits/Interest. All Tier 1 Deposits plus accrued interest will be applied to the Customer's account upon date of disconnection or at the time the Customer's September bill is prepared, whichever is earlier.

Tier 2 Deposits/Interest. A portion of the Tier 2 Deposit plus accrued interest equal to the monthly billing amount will be applied to the Customer's account each month until the Tier 2 Deposit amount plus accrued interest is depleted. Any Tier 2 Deposit amount and/or accrued interest remaining at the date of service disconnection or at the time of the Customer's September billing, whichever is earlier, will be applied to the Customer's account

Each irrigation Customer, upon making a deposit payment, will be required to furnish to the Company an IRS Tax Identification or Social Security number for the Company's IRS reporting requirements.

If a Customer tenders to the Company an irrigation deposit which has not been requested or demanded by the Company, the Company may refuse to accept and retain such deposit. If, however, the Company accepts or retains the deposit, the Company will apply the deposit to the Customer's account and no interest will be paid.

SCHEDULE 27
IRRIGATION EFFICIENCY
REWARDS PROGRAM

AVAILABILITY

Service under this schedule is available to agricultural irrigation customers taking service under Schedule 24 throughout the Company's service area within the State of Oregon and who meet the qualifications of the Irrigation Efficiency Rewards Program.

APPLICABILITY

Service under this schedule is applicable to energy efficiency projects related to existing or new agricultural irrigation systems that meet the requirements of the Irrigation Efficiency Rewards Program.

PROGRAM DESCRIPTION

The Irrigation Efficiency Rewards Program is an incentive based program designed to help cover a portion of the costs of designing and installing energy efficiency features into a new or existing irrigation system. The primary goal of this program is to encourage agricultural irrigation Customers to install or modify irrigation systems in order to reduce peak demand and energy consumption in their operations. The Irrigation Efficiency Rewards Program also encourages and assists agricultural irrigation Customers to use electricity in an economically efficient manner through education and information, expert energy audits, annual workshops, energy efficiency demonstration projects, and expert system analysis by a Company agricultural representative.

INCENTIVE OPTIONS

The two incentive options available to Customers under the Irrigation Efficiency Rewards Program are the Custom Option and the Menu Option. Under the Custom Option, Customers who wish to receive a financial incentive are required to submit an energy efficiency project proposal for review by the Company to determine project viability and cost-effectiveness. Upon approval by the Company, a financial incentive is paid to the Customer on the basis of the estimated annual energy savings or demand reduction that is expected to result from the project. Under the Menu Option, Customers select from a predetermined list of approved energy efficient equipment rebuild or repair measures. Customers selecting the Menu Option receive a financial incentive paid on the basis of the number of equipment units installed, replaced or repaired as documented by a copy of the purchase invoice provided to the Company by the Customer. The incentive amounts available under the Menu Option are limited to 100% of the purchase invoice cost except where noted.

SCHEDULE 27
IRRIGATION EFFICIENCY
REWARDS PROGRAM
(Continued)

Custom Option

Project viability will be determined by the Company. New and existing system project proposals submitted to the Company for consideration will be evaluated for program eligibility based upon the following information supplied by the Customer:

1. An itemized cost estimate from the equipment dealer, which must include the make, model and equipment specifications for both new and existing irrigation systems.

2. An irrigation system drawing that includes:

   a. Location of the pumps and water sources
   b. Mainline sizes, lengths, types and locations
   c. Elevations
   d. Number of irrigated acres

3. A pump curve detailing the number of stages and impeller diameter.

4. A topographical map of the irrigation system area.

5. An aerial map of the irrigated acres.

Applicable Projects		
Measure Type	Incentive	Eligibility Requirements
Existing system project	$0.25 per annual kilowatt-hour saved (kWh/yr) or $450.00 per kilowatt of demand reduction (kW)	Existing system project eligibility will be determined based upon the energy and demand savings estimated by the Company. The incentive for existing systems is limited to a cap of 75% of the total project cost.
New system project	$0.25 per annual kilowatt-hour saved (kWh/yr)	New system project eligibility will be determined based upon the energy savings estimated by the Company. The incentive for new systems is limited to a cap of 10% of the total project cost.

SCHEDULE 27
IRRIGATION EFFICIENCY
REWARDS PROGRAM
(Continued)

Menu Option

Applicable Measures		
Measure Type	Incentive	Eligibility Requirements
New flow control nozzles	$1.50 per nozzle	New flow control nozzles must replace existing brass nozzles or worn out flow control nozzles of the same flow rate or less to be eligible for an incentive under this option. The incentive amount is limited to two nozzles per sprinkled acre.
New nozzles	$0.25 per nozzle	New nozzles must replace worn out nozzles of the same flow rate or less to be eligible for an incentive under this option. The incentive amount is limited to two nozzles per sprinkled acre.
Rebuilt or new brass impact sprinklers	$2.75 per sprinkler* (see restriction)	New or rebuilt impact sprinklers replacing existing sprinklers on hand-lines, wheel-lines or solid type systems are eligible for an incentive under this option. Impact sprinklers must be rebuilt to like-new condition and are subject to verification by the Company. The incentive amount is limited to two heads per sprinkled acre.
New rotating type or low-pressure pivot sprinkler heads	$2.75 per sprinkler	New sprinkler heads must have an equal or lower flow rate than the replaced sprinkler heads to be eligible for an incentive under this option.
New low-pressure regulators	$5.00 per regulator	New low-pressure regulators with equal or lower pressure design than the replaced regulators are eligible for an incentive under this option.
New drains, riser caps and gaskets for hand lines, wheel-lines or portable mainlines	$1.00 per measure type* (see restriction)	Replacement of drains, riser caps and gaskets for components of existing hand-lines, wheel-lines or portable mainlines are eligible for an incentive under this option. The incentive amount is limited to two per measure type per sprinkled acre.
New wheel-line hubs	$12.00 per hub	Only Thunderbird brand wheel-lines are eligible for an incentive under this option.
New gooseneck with drop tube or boomback	$1.00 per measure type	New goosenecks with drop tubes or boombacks must be installed on an existing pivot to be eligible for an incentive under this option.
Cut and pipe press or weld repair	$8.00 per joint	Repaired leaking hand-lines, wheel-lines and portable mainlines are eligible for an incentive under this option.
* Incentive Restriction: Measure types indicated with a (*) are eligible for a maximum incentive amount equal to either the lesser of the stated incentive amount or 50% of the purchase invoice cost for each successfully installed measure.		

SCHEDULE 27
IRRIGATION EFFICIENCY
REWARDS PROGRAM
(Continued)

Menu Option (Continued)

Applicable Measures		
Measure Type	Incentive	Eligibility Requirements
New or rebuilt wheel-line levelers	$0.75 per leveler	New or rebuilt levelers replacing existing levelers are eligible for an incentive under this option. Levelers must be rebuilt to like-new condition and are subject to verification by the Company.
New center pivot base boot gasket	$125.00 per gasket	A new center pivot base boot gasket must replace an existing center pivot base boot gasket to be eligible for an incentive under this option. The incentive amount may exceed 100% of the purchase invoice cost whenever the installation is completed by the Customer.
* Incentive Restriction: Measure types indicated with a (*) are eligible for a maximum incentive amount equal to either the lesser of the stated incentive amount or 50% of the purchase invoice cost for each successfully installed measure.		

SCHEDULE 40
UNMETERED GENERAL SERVICE

AVAILABILITY

Service under this schedule is available at points on the Company's interconnected system within the State of Oregon where existing secondary distribution facilities of adequate capacity, phase and voltage are available adjacent to the Customer's Premises and the only investment required by the Company is an overhead service drop.

APPLICABILITY

Service under this schedule applies to Electric Service for the Customer's single- or multiple-unit loads up to 1,800 watts per unit where the size of the load and period of operation are fixed and, as a result, actual usage can be accurately determined. Service may include, but is not limited to, street and highway lighting, security lighting, telephone booths and CATV power supplies which serve line amplifiers. Equipment or loads constructed or operated in such a way as to allow for the potential or actual variation in energy use are not eligible for service under this schedule. Facilities to supply service under this schedule shall be installed so that service cannot be extended to the Customer's loads served under other schedules. Service under this schedule is not applicable to shared or temporary service, or to the Customer's loads on Premises which have metered service.

SPECIAL TERMS AND CONDITIONS

The Customer shall pay for all Company investment, except the overhead service drop, required to provide service requested by the Customer. The Customer is responsible for installing, owning and maintaining all equipment, including necessary underground circuitry and related facilities to connect with the Company's facilities at the Company designated Point of Delivery. If the Customer's equipment is not properly maintained, service to the specific equipment will be terminated.

Energy used by CATV power supplies which serve line amplifiers will be determined by the power supply manufacturer's nameplate input rating assuming continuous operation.

The Customer is responsible for notifying the Company of any changes or additions to the equipment or loads being served under this schedule. Failure to notify the Company of such changes or additions will result in the termination of service under this schedule and the requirement that service be provided under one of the Company's metered service schedules.

If the Customer modifies existing equipment being served under this schedule in a way that allows for the potential or actual variation in energy usage or installs additional equipment that allows for the potential or actual variation in energy usage, service under this schedule will be terminated and the Customer will be required to receive service under one of the Company's metered service schedules.

With Company approval, municipalities or agencies of federal, state, or county governments may install equipment that allows for the potential intermittent variation in energy usage at authorized Points of Delivery. Under these circumstances, the Customer's bill will include fixed units of the Intermittent Usage Charge in addition to the Customer's other Monthly Charges.

The Company is only responsible for supplying energy to the Point of Delivery and, at its expense, may check energy consumption at any time.

SCHEDULE 40
UNMETERED GENERAL SERVICE
(Continued)

MONTHLY CHARGE

The average monthly kWh of energy usage shall be estimated by the Company, based on the Customer's electric equipment and one-twelfth of the annual hours of operation thereof. Since the service provided is unmetered, failure of the Customer's equipment will not be reason for a reduction in the Monthly Charge. The Monthly Charge shall be computed at the following rate, and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Exactions).

Energy Charge, per kWh	~~5.2410~~7.4297¢
Power Supply Adjustment, per kWh	0.4116¢
Minimum Charge, per month	$ 1.50

ADDITIONAL CHARGES

Applicable only to municipalities or agencies of federal, state, or county governments with an authorized Point of Delivery having the potential of intermittent variations in energy usage.

Intermittent Usage Charge, per unit, per month	$1.00

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 41
STREET LIGHTING SERVICE

AVAILABILITY

Service under this schedule is available throughout the Company's service area within the State of Oregon where street lighting wires and fixtures can be installed on the Company's existing distribution facilities.

APPLICABILITY

Service under this schedule is applicable to service required by municipalities or agencies of federal, state, or county governments for the lighting of public streets, alleys, public grounds, and thoroughfares. Street lighting lamps will be energized each night from dusk until dawn.

SERVICE LOCATION AND PERIOD

Street lighting facility locations, type of unit and lamp sizes, as changed from time to time by written request of the Customer and agreed to by the Company, shall be ~~as shown on an Exhibit A~~provided for ~~each Customer~~Customers receiving service under this schedule. The in-service date for each street lighting facility ~~will be maintained on the Exhibit A~~shall also be maintained.

The minimum service period for any street lighting facility is 10 years. The Company, upon written notification from the Customer, will remove a street lighting facility:

1. At no cost to the Customer, if such facility has been in service for no less than the minimum service period. The Company will not grant a request from the Customer for reinstallation of street lighting service for a minimum period of two years from the date of removal.

2. Upon payment to the Company of the removal cost, if such facility has been in service for less than the minimum service period.

"A" - OVERHEAD LIGHTING - COMPANY-OWNED SYSTEM

The facilities required for supplying service, including fixture, lamp, control relay, mast arm ~~or~~for mounting on an existing utility pole, and energy for the operation thereof, are supplied, installed, owned and maintained by the Company. All necessary repairs and maintenance work, including group lamp replacement and glassware cleaning, will be performed by the Company during the regularly scheduled working hours of the Company on the Company's schedule. Individual lamps will be replaced on burnout as soon as reasonably possible after notification by the Customer and subject to the Company's operating schedules and requirements.

The Company has two standard street lighting fixture options, drop-glass or cut-off (shielded lighting). For each initial lighting fixture installation, the Customer is required to state, in writing, a fixture preference. A maintenance-related replacement of a current fixture will be made with a similar type of drop-glass or cut-off fixture as the one being replaced unless written notification has been received from the Customer requesting a change in fixture types.

~~Customers whose usage of the Company's system results in the potential or actual variation in energy usage, such as through, but not limited to, the use of wired outlets or useable plug-ins, are required to have metered service under this schedule.~~

SCHEDULE 41
STREET LIGHTING SERVICE
(Continued)

ACCELERATED REPLACEMENT OF EXISTING FIXTURES

In the event a Customer requests the Company perform an accelerated replacement of existing fixtures with the cut-off fixture, the following charges will apply:

1. The ~~actual~~designed cost estimate which includes labor, time, and mileage costs ~~incurred by the Company~~ for the removal of the existing street lighting fixtures.

2. $65.00 per fixture removed from service.

The total charges identified in 1 and 2 above must be paid prior to the beginning of the fixture replacement and are non-refundable. The accelerated replacement will be performed by the Company during the regularly scheduled working hours of the Company and on the Company's schedule.

MONTHLY ~~CHARGES~~CHARGE

The ~~Monthly Charge is the sum of the Monthly Lamp or Base Rate and the Power Supply Adjustment at the following rates~~Monthly Charges are as follows, and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Exactions).

~~Non-Metered Service~~Lamp Charges, per lamp

High Pressure Sodium Vapor	Average Lumens	Monthly Base Rate	Power Supply Adjustment
70 Watt	5,540	$ ~~6.63~~7.94	$ 0.10
100 Watt	8,550	$ ~~6.58~~7.89	$ 0.14
200 Watt	19,800	$ ~~8.04~~9.53	$ 0.28
250 Watt	24,750	$ ~~8.94~~10.54	$ 0.35
400 Watt	45,000	$ ~~11.26~~13.15	$ 0.56

~~ADDITIONAL MONTHLY RATE~~Pole Charges
For Company-owned poles required to be used for street lighting only:

Wood pole	$ 1.90 per pole
Steel pole	$ 7.39 per pole

Facilities Charges
Customers assessed a monthly facilities charge prior to August 8, 2005 for the installation of underground circuits will continue to be assessed a monthly facilities charge equal to 1.75 percent of the estimated cost difference between overhead and underground circuits.

~~Metered Service~~

~~Lamp Charges, per lamp~~
~~High Pressure Sodium Vapor~~

~~70 Watt~~	~~$ 5.45~~
~~100 Watt~~	~~$ 5.22~~
~~200 Watt~~	~~$ 5.32~~
~~250 Watt~~	~~$ 5.50~~

~~400 Watt~~	~~$ 5.78~~
~~Meter Charge, per meter~~	~~$ 8.00~~
~~Energy Charge, per kWh~~	~~4.0000¢~~
~~Power Supply Adjustment~~	~~0.4116¢~~

SCHEDULE 41
STREET LIGHTING SERVICE
(Continued)

"B" - CUSTOMER-OWNED SYSTEM

The Customer's lighting system, including posts or standards, fixtures, initial installation of lamps and underground cables with suitable terminals for connection to the Company's distribution system, is installed and owned by the Customer.

~~Service supplied by the Company includes operation of the system, energy, lamp renewals, cleaning of glassware, and replacement of defective photocells which are standard to the Company-owned street light units. Service does not include the labor or material cost of replacing cables, standards, broken glassware or fixtures, or painting or refinishing of metal poles.~~

Customer-owned systems constructed, operated, or modified in such a way as to allow for the potential or actual variation in energy usage, such as through, but not limited to, the use of wired outlets or useable plug-ins, are required to be metered in order to record actual energy usage.

ENERGY AND MAINTENANCE SERVICE

Energy and Maintenance Service includes operation of the system, energy, lamp renewals, cleaning of glassware, and replacement of defective photocells which are standard to the Company-owned street light units. Service does not include the labor or material cost of replacing cables, standards, broken glassware or fixtures, painting, or refinishing of metal poles. Individual lamps will be replaced on burnout as soon as reasonably possible after notification by the Customer and subject to the Company's operating schedules and requirements.

ENERGY ONLY SERVICE

Energy-Only Service is available only to a metered lighting system. Service includes energy supplied from the Company's overhead or underground circuits and does not include any maintenance to the Customer's facilities.

A street lighting system receiving service under the Energy-Only Service offering is not eligible to transfer to any street lighting service option under this schedule that includes maintenance provisions to the Customer's facilities.

SCHEDULE 41
STREET LIGHTING SERVICE
(Continued)

MONTHLY ~~CHARGES~~CHARGE

The Monthly Charges are as follows, and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Exactions).

Non-Metered Service (With Maintenance), per lamp

High Pressure Sodium Vapor	Average Lumens	Monthly Base Rate	Power Supply Adjustment
70 Watt	5,540	$ ~~3.51~~4.44	$ 0.10
100 Watt	8,550	$ ~~3.68~~4.63	$ 0.14
200 Watt	19,800	$ ~~5.15~~6.28	$ 0.28
250 Watt	24,750	$ ~~6.04~~7.28	$ 0.35
400 Watt	45,000	$ ~~8.36~~9.89	$ 0.56

Metered Service (With Maintenance), per lamp

Lamp Charge, per lamp
High Pressure Sodium Vapor

70 Watt	$ 2.~~55~~86
100 Watt	$ 2.~~32~~60
200 Watt	$ 2.~~43~~73
250 Watt	$ 2.~~60~~92
400 Watt	$ ~~2.88~~3.23

Meter Charge, per meter	$ 8.00
Energy Charge, per kWh	4.~~0000~~4984¢
Power Supply Adjustment, per kWh	0.4116¢

Metered Energy-Only Service (No Maintenance)

Meter Charge, per meter	$ 8.00
Energy Charge, per kWh	4.~~0000~~4984¢
Power Supply Adjustment, per kWh	0.4116¢

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 42
TRAFFIC CONTROL SIGNAL
LIGHTING SERVICE

APPLICABILITY

Service under this schedule is applicable to Electric Service required for the operation of traffic control signal lights within the State of Oregon. Traffic control signal lamps are mounted on posts or standards by means of brackets, mast arms, or cable.

CHARACTER OF SERVICE

The traffic control signal fixtures, including posts or standards, brackets, mast arm, cable, lamps, control mechanisms, fixtures, service cable, and conduit to the point of, and with suitable terminals for, connection to the Company's underground or overhead distribution system, are installed, owned, maintained and operated by the Customer. Service is limited to the supply of energy only for the operation of traffic control signal lights.

The installation of a meter to record actual energy consumption is required for all new traffic control signal lighting systems installed on or after August 8, 2005. For traffic control signal lighting systems installed prior to August 8, 2005 a meter may be installed to record actual usage upon the mutual consent of the Customer and the Company.

MONTHLY ~~CHARGES~~CHARGE

The monthly kWh of energy usage shall be either the amount estimated by the Company based on the number and size of lamps burning simultaneously in each signal and the average number of hours per day the signal is operated, or the actual meter reading as applicable. The Monthly Charge shall be computed at the following rate, and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Exactions).

Energy Charge, per kWh	~~3.8500~~7.4265¢
Power Supply Adjustment, per kWh	0.4116¢

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 55
ANNUAL POWER COST UPDATE

PURPOSE

The purpose of this adjustment schedule is to define procedures for annual rate revisions due to changes in the Company's projected Net Power Supply Expense. This schedule is an "automatic adjustment clause" as defined in ORS 757.210(1). The Annual Power Cost Update (APCU) will be comprised of two components: an October Power Cost Update ("October Update") and a March Power Cost Forecast ("March Forecast").

APPLICABILITY

This schedule is applicable to all electric energy delivered to Customers served under Schedules 1, 7, 9, 15, 19, 24, 40, 41, and 42.

NET POWER SUPPLY EXPENSE

Net Power Supply Expense (NPSE) includes the amounts booked to FERC Accounts 501 (Fuel-Coal), 547 (Fuel-Gas), 555 (Purchased Power), and 447 (Sales for Resale).

RATES

This adjustment rate is subject to increases or decreases which may be made without prior hearing to reflect increases or decreases, or both, in NPSE.

APCU - OCTOBER UPDATE

The October update filing, which will be based on a test period of the following April through March ("April through March Test Period"), will reflect a normalized look, on a system-wide basis, at the Company's NPSE. A normalized look means the October update will incorporate data reflecting normal loads and average costs associated with multiple stream flow conditions.

The following variables are updated for each October Update:

- Fuel prices and transportation costs;
- Wheeling expenses;
- Planned outages and forced outage rates;
- Heat rates;
- Forecast of Normalized Sales and Normalized Load determined in accordance with the methodology employed in the most recently acknowledged Integrated Resource Plan ("IRP");
- Contracts for wholesale power and power purchases and sales;
- PURPA contract expenses;
- The Oregon state allocation factor; and
- The average forward electric price curve calculated from the previous October through September daily Mid-Columbia heavy load and light load forward price curves for the period April through March immediately following the April through March Test Period, adjusted for inflation back one year.

SCHEDULE 55
ANNUAL POWER COST UPDATE
(Continued)

APCU - OCTOBER UPDATE (Continued)

The output of the Company's power supply model will be used to determine the net power supply average dispatch for normal loads and an average of stream flow conditions. The volume of purchased power and surplus sales determined from the output of the Company's power supply model normalized run will be re-priced using the average forward price curve modified in the following manner:

Purchased Power

- Heavy Load - 3.9% above average Mid-C HL prices
- Light Load - 7.1% above average Mid-C LL prices

Surplus Sales

- Heavy Load - 3.6% below average Mid-C HL prices
- Light Load - 6.6% below average Mid-C LL prices

The October Update Rate for power supply expense will be the Base Power Costs divided by the Normalized Sales. Base Power Costs are the total power supply expense dollars determined by the procedures described above.

APCU - MARCH FORECAST

The March Forecast filing will reflect the Company's estimate of expected power supply expenses for April through March Test Period, allowing for the most recent updates to the following variables:

- Fuel prices and transportation costs;
- Wheeling expenses;
- Planned outages and forced outage rates;
- Heat rates;
- Forecast of Normalized Sales and Normalized Loads, updated only for known significant changes since the October Annual Power Cost Update filing;
- Forecast hydro generation from stream flow conditions using the most recent water supply forecast from the Northwest River Forecast Center in Portland, Oregon, and current reservoir levels;
- Contracts for wholesale power and power purchases and sales;
- PURPA contract expenses;
- The Oregon state allocation factor; and
- The most recent monthly forward price curve, as of the date of the filing, for the April through March Test Period.

The output of a single water condition run of the Company's power supply model for the April through March Test Period, with updated stream flow conditions and reservoir levels, will be used to determine the March Forecast of NPSE. The volume of purchased power and surplus sales will be re-priced using the most recent monthly forward price curve, with heavy load and light load mid-Columbia prices modified in the following manner.

SCHEDULE 55
ANNUAL POWER COST UPDATE
(Continued)

APCU - MARCH FORECAST (Continued)

Purchased Power

- Heavy Load - 3.9% above average Mid-C HL prices
- Light Load - 7.1% above average Mid-C LL prices

Surplus Sales

- Heavy Load - 3.6% below average Mid-C HL prices
- Light Load - 6.6% below average Mid-C LL prices

The March Forecast Rate for power supply expense will be the Forecast Power Costs determined by the procedures described above, divided by the Forecast Normalized sales.

CHANGES IN NET POWER SUPPLY EXPENSE

Changes in NPSE are defined as the projected per unit change in NPSE from the per unit NPSE used to develop the Energy Charge for the applicable rate schedules. Unit NPSE are defined as the total NPSE divided by Normalized Sales for the April through March Test Period.

FILING AND EFFECTIVE DATE

In October of each year, the Company will file its October Update with an effective date of June 1 of the following year.

In March of each year the Company will file its March Forecast with an effective date of June 1 following the filing.

RATE ADJUSTMENT

The Sales Adjusted Forecast Power Cost Change is the March Forecast Rate less the October Update Rate, the result multiplied by the Forecast Sales.

The Forecast Change Allowed is 95% of the Sales Adjusted Forecast Power Cost charge.

The March Forecast Rate Adjustment is the Forecast Change Allowed divided by Forecast Sales.

The Combined Rate is the sum of the October Update Rate and the March Forecast Rate Adjustment.

The rate adjustment is the difference between the Combined Rate and the unit NPSE included in the current base rate. The rate adjustment is applied to each of the schedules on an equal cents per kWh basis.

ADJUSTMENT RATES

Schedule	Description	¢ per kWh
1	Residential Service	1.2570
7	Small General Service	1.2570
9	Large Power Service	1.2570
15	Dusk to Dawn Lighting	1.2570
19	Large Power Service	1.2570
24	Irrigation Service	1.2570
40	Unmetered General Service	1.2570
41	Municipal Street Lighting	1.2570
42	Traffic Control Lighting	1.2570

SCHEDULE 56
POWER COST ADJUSTMENT MECHANISM

PURPOSE

To recognize in rates part of the difference between actual net power supply expenses incurred for the preceding January through December period and the net power supply expenses recovered through Schedule 55 for that same period.

APPLICABILITY

This schedule is applicable to all electric energy delivered to Customers served under Schedules 1, 7, 9, 15, 19, 24, 40, 41 and 42.

ANNUAL POWER COST ADJUSTMENT (PCA)

Subject to the 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.

ANNUAL POWER SUPPLY EXPENSE TRUE-UP BALANCING ACCOUNT (TRUE-UP BALANCING ACCOUNT)

The True-Up Balancing Account is a Company account where the PCA will be added at the end of each 12-month period ending December, along with 50 percent of the annual interest calculated at the Company's authorized cost of capital. Interest will accrue on the True-Up Balancing Account at the Commission-authorized rate for deferred accounts.

EARNINGS TEST

Before any PCA amount is approved for inclusion in the True-Up Balancing Account for subsequent recovery or refund in rates, the Commission will apply an Earnings Test.

If the Company'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 PCA 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 PCA amount 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 PCA amount in the True-Up Balancing Account as a credit, down to the authorized ROE plus 100 basis points threshold.

DEFINITIONS

Actual Net Power Supply Expenses (Actual NPSE)

Actual NPSE is determined on a system-wide basis and includes the amounts booked to FERC Accounts 501 (Fuel-Coal), 547 (Fuel-Gas), 555 (Purchased Power), and 447 (Sales for Resale).

SCHEDULE 56
POWER COST ADJUSTMENT MECHANISM
(Continued)

DEFINITIONS (Continued)

Actual Sales

Actual Sales is the amount of energy required to meet customer demand on a system-wide basis, as measured at the customers' meters.

Actual Unit Cost

The Actual Unit Cost for net power supply expenses incurred is the total Actual NPSE incurred divided by Actual Sales.

Combined Rate

The Combined Rate is the sum of the October Update Rate and the March Forecast Rate Adjustment, as determined by the Annual Power Cost Update, Schedule 55.

Normalized Sales

Normalized Sales is a forecast of the amount of energy required to meet customer demand on a system-wide basis, as measured at the customers' meters, determined in accordance with the methodology employed in the Company's most recently acknowledged Integrated Resource Plan ("IRP").

Oregon Allocated Power Cost Deviation

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.

Power Supply Expense Deadband

A Power Supply Expense Deadband (Deadband) based upon the Company's authorized ROE from its last general rate case and using the rate base measured on an Oregon basis from the most recent Oregon Results of Operations report (Oregon basis), is applied to the Oregon Allocated Power Cost Deviation as follows:

1. 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).

2. 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).

SCHEDULE 56
POWER COST ADJUSTMENT MECHANISM
(Continued)

ANNUAL POWER SUPPLY EXPENSE TRUE-UP

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.

TIME OF FILING

In February of each year, beginning in February of 2009, the Company will file the Annual Power Supply Expense True-Up which will implement the Power Cost Adjustment Mechanism. This filing will calculate 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 costs are first calculated on a total system basis and then allocated to Oregon based on the allocation factor.

TRUE-UP RATES

The True-Up Rates (Annual Power Supply Expense True-Up) will be determined on an equal cents per kWh basis. The True-Up Rates are:

Schedule	Description	¢ per kWh
1	Residential Service	0.0000
7	Small General Service	0.0000
9	Large Power Service	0.0000
15	Dusk to Dawn Lighting	0.0000
19	Large Power Service	0.0000
24	Irrigation Service	0.0000
40	Unmetered General Service	0.0000
41	Municipal Street Lighting	0.0000
42	Traffic control Lighting	0.0000

SCHEDULE 60
SOLAR PHOTOVOLTAIC SERVICE
PILOT PROGRAM

AVAILABILITY

Service under this schedule is available to Customers who have entered into a Uniform Solar Photovoltaic Service Agreement with the Company. New service under this schedule will not be available after November 15, 1996.

DEFINITIONS

Photovoltaic System is the solar photovoltaic module(s), the module mounting structure, the control structure, the control equipment, any necessary wiring, any batteries and/or back-up generator, if required, and any other equipment necessary to provide service under this schedule. The Company shall have sole ownership of the Photovoltaic System during the term of the Uniform Solar Photovoltaic Service Agreement.

Point of Service is the point where the Customer's electric system is connected to the Photovoltaic System.

Total Installed Cost is the estimated total cost for the installation of, or modification to, the Photovoltaic System including but not limited to the Company's investment in facilities, labor, material and supplies, and overheads.

Net Installed Cost is the Total Installed Cost less the Initial Fee.

Customer Site is the installation site and facilities as determined by the Company which are necessary for the installation of the Photovoltaic System. The Customer Site facilities are not included as part of the Photovoltaic System unless specifically stated by the Company and included in the Solar Photovoltaic Facilities Investment Report.

Salvage Value is the market value of the photovoltaic facilities at the time they are removed from the Customer's premises.

Facility Termination Charge is the Total Installed Cost of the Photovoltaic System less the sum of 80 percent of the accumulated depreciation and 60 percent of the Salvage Value of the facilities removed plus the removal cost. In no event will the Facility Termination Charge be less than the removal cost.

ELIGIBILITY

Requests for service under this schedule which have a Total Installed Cost of no more than $50,000, which are located in areas reasonably accessible by standard utility vehicles, and which are cost effective alternatives are eligible for service under this schedule. In determining eligibility under this schedule, the Company will consider the remoteness, accessibility, load size, load profile, solar resource, and solar impediments of the requested site as well as the suitability of the Customer Site. Requests which have special access requirements may be granted at the discretion of the Company provided that reasonable alternative access provisions are met and/or the Company is compensated for its special access related costs. Any special access provisions will be included in an addendum to the Uniform Solar Photovoltaic Service Agreement. The Company has the sole right to ultimately determine eligibility under this schedule.

SCHEDULE 60
SOLAR PHOTOVOLTAIC SERVICE
PILOT PROGRAM
(Continued)

INITIAL FEE

An Initial Fee equal to 5 percent of the Total Installed Cost of the Photovoltaic System is required from the Customer at the time the Uniform Solar Photovoltaic Service Agreement is executed. If a modification to the Photovoltaic System which increases the Total Installed Cost is requested subsequent to the time the Uniform Solar Photovoltaic Service Agreement is executed, an additional Initial Fee equal to 5 percent of the Total Installed Cost of the modification will be required prior to the installation of such modification to the Photovoltaic System. The Initial Fee is non-refundable unless the Company determines that it will not install the Photovoltaic System.

SERVICES PROVIDED

The Photovoltaic System will be specified by the Company based upon the service requirements requested by the Customer. Upon determination by the Company that the Customer is eligible for service under this schedule, and upon receipt from the Customer of the Initial Fee, the Company will proceed with the installation plans for the Photovoltaic System.

All repair and maintenance of the Photovoltaic System will be provided by the Company. Prudent utility practices will be followed for all necessary repair or maintenance. The Company will use its best effort to provide the Customer a minimum of 24 hours notice prior to performing preventative maintenance.

The Customer is responsible for providing the Customer Site and the connections from the Point of Service to the Customer's facilities, and for permitting the Company appropriate access to the Photovoltaic System. The Customer Site and Customer connections must be approved by the Company and must meet all State and Local Codes. The Company may, at its sole discretion, install and/or own Customer Site facilities and include the cost of such facilities in the Total Installed Cost.

If a back-up generator is included with the Photovoltaic System, the Customer is responsible for providing, at the Customer's expense, the fuel required for the operation of such generator.

SERVICE LIMITATIONS

Electric service under this schedule is limited to that provided by the Photovoltaic System. The Company is under no obligation to provide Electric Service to the Customer at any time by means of the Company's transmission or distribution system.

CUSTOMER NON-COMPLIANCE

Any use by the Customer of the Photovoltaic System not in compliance with the design specifications for such system or not in compliance with the provisions of this schedule may result in the removal by the Company of the Photovoltaic System. The Company reserves the right to remove the Photovoltaic System if the Company determines that the continued use of the facilities by the Customer poses a threat of injury or damage to persons or property. Non-payment of the monthly charges under this schedule may also result in the removal by the Company of the Photovoltaic System.

In the event the Company removes the Photovoltaic System under the provisions of this section, the Customer will be obligated to pay to the Company the Facility Termination Charge.

SCHEDULE 60
SOLAR PHOTOVOLTAIC SERVICE
PILOT PROGRAM
(Continued)

SOLAR PHOTOVOLTAIC FACILITIES INVESTMENT REPORT

The Total Installed Cost of the Photovoltaic System will be set forth in a Solar Photovoltaic Facilities Investment Report provided to the Customer. The monthly charge for service under this schedule is based on the Total Installed Cost, less the Initial Fee, as reflected on this Report. When the actual book cost of the installed Photovoltaic System has been determined by the Company, the Total Installed Cost will be adjusted to reflect the actual cost and the corresponding monthly charge will be reduced if the actual cost is more than 10 percent less than the Total Installed Cost included on the Report. In no event will the monthly charge be increased if the actual cost is greater than the Total Installed Cost.

PHOTOVOLTAIC SYSTEM MODIFICATIONS

If the Photovoltaic System is modified in order to provide for changes in the Customer's service requirements, the Solar Photovoltaic Facilities Investment Report and the corresponding monthly charge for service will be adjusted to reflect the modification.

Additions. If the Customer requests a modification to the Photovoltaic System, the Customer will be required to pay an additional Initial Fee equal to 5 percent of the Total Installed Cost of the modification prior to the installation of the modification.

Removals. If the Customer requests a portion of the Photovoltaic System be removed, the Customer shall pay to the Company the Facility Termination Charge for that portion of the Photovoltaic System removed. If the Customer requests the Photovoltaic System in its entirety be removed, the provisions of the Agreement Termination section below will apply.

AGREEMENT TERMINATION

Customer Termination. If the Customer cancels the Uniform Solar Photovoltaic Service Agreement at the end of any of the five year terms of the Agreement, the Customer shall have the option of either 1) purchasing the Photovoltaic System at the Company's Total Installed Cost less accumulated depreciation, or 2) requesting the Company remove the Photovoltaic System and paying to the Company the cost of removing the facilities. If the Customer cancels the Uniform Solar Photovoltaic Service Agreement during the term of the Agreement, the Customer shall pay to the Company the Facility Termination Charge.

Company Termination. If the Company cancels the Uniform Solar Photovoltaic Service Agreement at any time and for any reason other than Customer Non-Compliance, the Company shall offer the Customer the option of either; (1) purchasing the Photovoltaic System at the Company's Total Installed Cost less accumulated depreciation, or (2) requesting the Company remove the Photovoltaic System at no cost to the Customer.

SCHEDULE 60
SOLAR PHOTOVOLTAIC SERVICE
PILOT PROGRAM
(Continued)

CHARGES

The monthly charge for service under this schedule is 1.6 percent times the Net Installed Cost of the Photovoltaic System as set forth on the Solar Photovoltaic Facilities Investment Report.

Back-up Generator Maintenance Charge: If the hours of usage of a back-up generator included with the Photovoltaic System exceeds the number of hours of usage specified in the design specifications by 20 percent or more on an annual basis, the Customer will be responsible for paying the additional maintenance costs incurred by the Company as a result of such overuse. The Company will notify the Customer in writing of any observed overuse of the back-up generator.

PAYMENT

The monthly bill rendered for service provided hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 60
SOLAR PHOTOVOLTAIC SERVICE
PILOT PROGRAM

IDAHO POWER COMPANY
Uniform Solar Photovoltaic
Service Agreement

DISTRICT ______________________ ACCOUNT NO. ____

THIS AGREEMENT Made this ______ day of ____________, 19 ______, between______________ ____, whose billing address is____ hereinafter called Customer, and IDAHO POWER COMPANY, A corporation with its principal office located at 1221 West Idaho Street, Boise, Idaho, hereinafter called Company:

NOW THEREFORE, The parties agree as follows:

1. Company will provide solar photovoltaic service for Customer's facilities located at or near

___________________________, County of _________________________________, State of Oregon.

2. Customer will:

a. Make an Initial Fee payment to the Company of $____________ at the time this Agreement is executed.

b. Provide the installation site and facilities as determined by the Company which are necessary for the installation of the Photovoltaic System and which are acceptable to the Company, and the right of the Company for appropriate access to the Company's facilities with the right of ingress and egress, at no cost to the Company.

3. This Agreement will not become binding upon the parties until signed by both parties.

4. The initial date of service under this Agreement is subject to the Company's ability to obtain the required labor, materials, and equipment, a satisfactory site, and satisfactory access to the Photovoltaic System on the Customer's property, and to comply with governmental regulations.

5. The term of this Agreement will be for five years from and after the Initial Service Date thereof, and will automatically renew for an additional five years each five years thereafter unless canceled by either party. This Agreement may be canceled 1) by either party after any of the five year terms provided written notice of termination is given to the other not less than three months prior to the end of the five year term, or 2) at any time provided both parties agree in writing to the cancellation. In the event the Company's Schedule 60 is terminated during the term of this Agreement, this Agreement will automatically be canceled and the Customer will have the option to purchase the Photovoltaic System at the Company's depreciated book value.

6. This Agreement will be binding upon the respective successors and assigns of the Customer and the Company, provided however, that no assignment by the Customer will be effective without the Company's prior written consent. The Company's consent will not be unreasonably withheld.

7. This Agreement is subject to valid laws and to the regulatory authority and orders, rules and regulations of the Oregon Public Utility Commission as now or may be hereafter modified and approved by the Oregon Public Utility Commission.

IDAHO POWER COMPANY
Uniform Solar Photovoltaic
Service Agreement
(Continued)

8. The Company's Schedule 60, as well as Idaho Power Company's General Rules and Regulations, any revisions to Schedule 60 or to the General Rules and Regulations, and/or any successor schedule or rules, are to be considered as part of this Agreement.

9. The Company will not be held responsible or liable for any loss, damage, or injury caused to its Customer or any other persons by the interruption, suspension, or fluctuation in service provided by the Photovoltaic System.

10. The Customer will agree to protect, defend, and indemnify Idaho Power Company from and against any costs, damages, or claims arising in any way from any injury to persons or damage to property resulting from the installation and/or operation of the Photovoltaic System upon Customer's property, providing such injury to persons or damage to property is not due to the sole negligence of Idaho Power Company.

11. In any action at law or equity commenced under this Agreement and upon which judgment is rendered, the prevailing party, as part of such judgment, will be entitled to recover all costs, including reasonable attorneys fees, incurred on account of such action.

Date ______________________, 19______

Initial Service Date______________________

(APPROPRIATE SIGNATURES)

SCHEDULE 61
POWER QUALITY PROGRAM

AVAILABILITY

Service under this Schedule is available to Customers throughout the Company's service area within the State of Oregon.

PROGRAM DESCRIPTION

The Power Quality Program is intended to provide Customers with a mechanism to identify and correct electrical problems within the Customer's residence or business which impact the Customer's power quality.

SERVICES PROVIDED

The Company will provide the following services:

Technical Assistance: The Company will perform a symptomatic audit of the Customer's residence or business to assist the Customer in identifying the probable cause of any power quality problems and possible solutions to any power quality problems identified. Technical Assistance is provided at no charge to the Customer.

Home Wiring Audit: A $~~25~~ 40 payment is provided by the Company to residential Customers who have a home wiring audit ~~for power quality~~ performed by a licensed electrician participating ~~in the Company's Power Quality Program~~. To have a home wiring audit performed, a Customer is responsible for contacting the Company to request the Home Wiring Audit form and then ~~can~~ contacting a licensed electrician to perform the audit. ~~the Company or an electrician participating in the Power Quality Program. Customers contacting the Company will be given a list of electricians participating in the Power Quality Program.~~ The Customer is also responsible for ~~selecting~~ ensuring the electrician ~~to~~ performs the audit per the instructions of the Home Wiring Audit form. The charge for the audit will be established by the electrician and will be billed by the electrician directly to the Customer. The Customer is responsible for paying the electrician the charge for performing the audit.

The $~~25~~40 payment is provided to the Customer upon receipt by the Company of the appropriate copy of the completed Home Wiring Audit form. The Customer is responsible for submitting the Home Wiring Audit form to the Company.

Purpose of Payment: The purpose of the $40 payment is to assist the Customer in identifying any wiring deficiencies that may be causing power usage problems. The payment is not an indication that the Company has performed any analysis as to the safety of the Customer's wiring or that the Company concurs with the findings of the electrician's wiring audit.

~~Financing: Financing through the Company is offered for the purchase of equipment or repairs to correct power quality problems. The equipment and repairs eligible for financing under the Power Quality Program include transient surge protectors, power conditioning equipment, uninterruptible power supplies, grounding repairs, service entrance repairs and upgrades, and wiring and outlet repairs.~~

~~Financing is available at the fixed rate of interest in effect for the Power Quality Program at the time the loan is made. The fixed rate is adjusted on January 1, May 1, and September 1 of each year. Repayment of the loan is collected through the Customer's monthly billing. Two loan categories are available: $25 to $400 and $401 to $10,000. The financing arrangements for each category are:~~

~~1. $25 through $400: The minimum monthly payment is $10. The interest rate is set equal to the prime rate of interest in effect on the first business day of the month immediately preceding the adjustment month.~~

~~2. $401 through $10,000: The minimum monthly payment is $15. The interest rate is set equal to the prime rate of interest in effect on the first business day of the month immediately preceding the adjustment month plus three percent. Customer taking loans of less than $10,000 must repay the loan amount within 30 months. For all other loan amounts, residential Customers can make monthly payments over 30, 60, 90, or 120 months; commercial Customers can make monthly payments over 30 or 60 months.~~

SCHEDULE 62
GREEN ENERGY PURCHASE
PROGRAM RIDER
(OPTIONAL)

PURPOSE

The Green Energy Purchase Program is an optional, voluntary program designed to provide customers an opportunity to participate in the purchase of new environmentally friendly "green" energy. Funds collected in this program will be wholly distributed to the purchase of Green Energy Products.

APPLICABILITY

Service under this schedule is applicable to all Customerss and non-customers who choose to participate in this Program.

MONTHLY GREEN ENERGY PURCHASE CONTRIBUTION

Customers designate their level of participation by choosing a fixed dollar per month amount. The monthly Green Energy Purchase Program contribution is in addition to all other charges included in the service schedule under which the Customer receives electrical service and will be added to the Customer's monthly electric bill. Non-Customer participants will be issued a monthly invoice that reflects their designated fixed dollar per month contribution.

The Program funds will wholly be used to purchase green energy or to cover the green energy price premium. The Company will acquire Green Energy Products within one year of the Customer's purchase under this Schedule.

GREEN ENERGY PRODUCTS

For purposes of this Program, green energy products include but are not limited to the following:

Green Tags. Green tags consist of the Non-Power Attributes resulting from the generation of energy by a qualified renewable resource. Such attributes may be fuel, emissions, or other environmental characteristics deemed of value by a green tag buyer. The price of Green Tags may include administration costs of the Green Tag broker.

Non-Power Attributes include but are not limited to any avoided emissions of pollutants to the air, soil or water such as sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO) and any other pollutant that is now or may in the future be regulated under the pollution control laws of the United States; and further include any avoided emissions of carbon dioxide (CO_2), methane (CH_4) and any other greenhouse gas (GHG) that contributes to the actual or potential threat of altering the Earth's climate. Non-Power Attributes are expressed in MWh.

Non-Power Attributes do not include any energy, capacity, reliability or other power attributes used to provide electricity services.

PROGRAM CONSIDERATIONS

No electric service disconnections will result in the event of non-payment of Program commitments.

SCHEDULE 66
MISCELLANEOUS CHARGES

PURPOSE

The purpose of this schedule is to accumulate all miscellaneous charges that are included in the Company's Rules, Regulations, and Rates.

APPLICABILITY

This schedule applies to all Customers taking service under the Company's Oregon Tariff except as expressly limited by a Rule or a Schedule.

CHARGES

RULE D ~~CHARGE~~

1. Instrument Transformer Metering

Current Transformer

Single Phase	
120/240 Volt	$214.00
240/480 Volt	$247.00
120/208 Volt Network	$275.00
Polyphase	
120/240 Volt Delta	$437.00
240/480 Volt Delta	$438.00
120/208 Volt Wye	$467.00
277/480 Volt Wye	$471.00

Voltage Transformer (secondary voltages only)
~~(secondary voltages only)~~Additional cost per voltage transformer $160.00

Primary Metering ~~Actual Cost~~
Work Order costs are applicable.

2. Off-Site Meter Reading Service

Single-Phase, Non-Demand Metering

Class 200 R300 Register (standard metering)	$ 3.65 per month
Class 320 R300 Register (standard metering)	$ 4.40 per month
Class 10 R 300 Register (instrument transformer metering)	$ 4.40 per month
Installation Fee (payable with first monthly payment)	$ 25.00
Removal Fee (if removed within 90 days of installation)	$ 25.00

SCHEDULE 66
MISCELLANEOUS CHARGES
(Continued)

RULE D (Continued)

3. Load Profile Metering

Pulse Output Service

With an existing Electronic Demand Meter	$ 5.00 per month
Without an existing Electronic Demand Meter	$ 13.00 per month
Installation Fee (payable with first monthly payment)	$ 70.00
Removal Fee (if removed within 90 days of installation)	$ 60.00

Load Profile Recording Service

With an existing Electronic Demand Meter	$ 17.50 per month
Without an existing Electronic Demand Meter	$ 25.50 per month
Installation Fee (payable with first monthly payment)	$ 80.00
Removal Fee (if removed within 90 days of installation)	$ 60.00

4. Special Meter Test

Non-Residential	Actual Labor & Mileage Rates
Residential	Not to Exceed $30.00

5. Surge Protection Device Services

Surge Protection Device Installation or Removal Charge	$ 43.00
Surge Protection Device Customer Visit Charge	$ 25.00

RULE F (all times are stated in Mountain Time)

6. Service Establishment Charge	$ 20.00
7. Continuous Service Reversion Charge	$ 10.00
8. Field Visit Charge	$ 20.00

9. Service Connection Charge

Schedules 1, 7, 9

Monday through Friday

7:30 am to 6:00 pm	$ 20.00
6:01 pm to 9:00 pm	$ 45.00
9:01 pm to 7:29 am	$ 80.00

Company Holidays and Weekends

7:30 am to 9:00 pm	$ 45.00
9:01 pm to 7:29 am	$ 80.00

SCHEDULE 66
MISCELLANEOUS CHARGES
(Continued)

RULE F (all times are stated in Mountain Time) (Continued)

9. Service Connection Charge (Continued)

Schedules 15, 19, 24, 40, 41, 42

Monday through Friday

7:30 am to 6:00 pm	$ 40.00
6:01 pm to 9:00 pm	$ 65.00
9:01 pm to 7:29 am	$100.00

Company Holidays and Weekends

7:30 am to 9:00 pm	$ 65.00
9:01 pm to 7:29 am	$100.00

~~Regular Business Hours (1)~~

~~Schedules 1, 7, 9~~	~~$ 20.00~~
~~Schedules 15, 19, 24, 40, 41, 42~~	~~$ 40.00~~

~~Non Regular Business Hours~~

~~Tier 1 (2)~~

~~Schedules 1, 7, 9~~	~~$ 45.00~~
~~Schedules 15, 19, 24, 40, 41, 42~~	~~$ 65.00~~

~~Tier 2 (3)~~

~~Schedules 1, 7, 9~~	~~$ 80.00~~
~~Schedules 15, 19, 24, 40, 41, 42~~	~~$100.00~~

~~(1) Customer request between 7:30 a.m. to 6:00 p.m., Monday-Friday, except Company-recognized holidays.~~
~~(2) Customer request between 6:01 p.m. to 9:00 p.m., Monday-Friday. Company recognized holidays and weekends between 7:30 a.m. to 9:00 p.m.~~
~~(3) Customer request for between 9:01 p.m. to 7:29 a.m., Monday-Friday. Company recognized holidays and weekends between 9:01 p.m. to 7:29 a.m.~~

10. Unauthorized Reconnection Charge $ 50.00

RULE G

11. Returned Check Charge $ 20.00

12. Fractional Period Minimum Billings

Schedules 1 and 7	$ 3.00
Schedules 9 and 19 Secondary	$ 5.00
Schedules 9 and 19 Primary & Transmission	$ 10.00
Schedule 24	$ 3.00
Schedule 15	$ 3.00
Schedule 40	$ 1.50

RULE H

13. Temporary Service Return Trip Charge $ 35.00

SCHEDULE 70
APPLIANCE RECYCLING PROGRAM

This schedule describes the Appliance Recycling Program (Program) offered by the Company and coordinated by JACO Environmental, Inc (JACO).

AVAILABILITY

This program is available to residential customers living in single and multi-family residences, including manufactured and modular homes, who remove and recycle a refrigerator or freezer and who live within the Company's service territory within the State of Oregon.

PROGRAM DESCRIPTION

The Appliance Recycling Program is an incentive-based program designed to encourage the removal and recycling of less efficient appliances by providing a $30 incentive to participating customers. To participate, Customers will schedule an appointment with JACO by phone or website to have their unit collected. JACO will pick up the unit from the Customer's home, transport, dismantle and recycle the unit.

TERMS AND CONDITIONS

By participating in the Program, Customers will be subject to the following terms and conditions:

1. Functioning units only.
2. Secondary units are preferred but incentive is available for the replacement of a primary unit.
3. Unit must be 10 to 30 cubic feet.
4. Clear path of removal must exist.
5. Maximum participation of two units per customer, per year.

SCHEDULE 71
DUCTLESS HEAT PUMP PILOT PROGRAM

This Schedule describes the Ductless Heat Pump Pilot Program offered by the Company and coordinated by the Northwest Energy Efficiency Alliance (NEEA).

AVAILABILITY

This program is available to residential customers living in single-family residences, including manufactured homes with permanent foundations, where no natural gas service is available, who live within the Company's service territory within the State of Oregon and have a ductless heat pump installed.

APPLICABILITY

Service under this schedule applies to customers who have lived in their home at least one full year prior to participation in the Ductless Heat Pump Pilot Program, have used electric heat as their primary heating source for the past year, and expect to live in their home for the two years following installation. The Program will commence on April 22, 2009. Equipment installation can occur until December 31, 2009 and field monitoring on installed equipment will occur through December 31, 2010.

PROGRAM DESCRIPTION

The Ductless Heat Pump Pilot Program is an incentive-based program designed to help cover a portion of the costs of installing an energy efficient ductless heat pump by providing a $1000 incentive to participating customers. The ductless heat pump installed must be a split system heat pump with an inverter driven, variable speed compressor, a variable speed outdoor fan, and a multi-speed or variable speed indoor blower. The equipment must be installed with the indoor unit located in the main living area of the house. Indoor units using any type of field-installed duct system are not eligible.

TERMS AND CONDITIONS

Upon acceptance into the Program, Customers will be subject to the following terms and conditions:

1. Participants must allow the Company to make their billing history available to the program evaluators for up to two years prior to and two years post installation,
2. Participating homes cannot be new construction, and
3. Participants must agree to the terms and conditions of the Ductless Heat Pump Pilot Program, as coordinated by NEEA.

SCHEDULE 72
HEATING AND COOLING EFFICIENCY PROGRAM

AVAILABILITY

Service under this schedule is available to residential Customers and owners or managers of rental properties throughout the Company's service area within the State of Oregon that are served under a residential electric service schedule. This schedule is also available to home builders and developers who construct homes in the Company's service area within the State of Oregon that take service under a residential electric service schedule upon completion.

APPLICABILITY

This program is applicable to site-built or manufactured homes served under a residential electric service schedule and sited in the Company's Oregon service territory.

PROGRAM DESCRIPTION

The Heating and Cooling Efficiency Program provides incentives for the proper sizing and installation of energy efficient heat pump equipment and for the purchase and installation of evaporative cooling equipment.

INCENTIVE STRUCTURE

To be eligible for an incentive, purchase and installation of the qualifying equipment cannot have started prior to May 1, 2009. Installation of heating and cooling equipment must have been performed by a participating company w ho has received program training and has signed an agreement with the Company, except for evaporative cooling equipment which does not require contractor training and installation. Installed measures must meet the requirements of the Heating and Cooling Efficiency Program as outlined in the Program Requirements Manual. To view a list of the participating companies and a current Program Requirements Manual, visit www.idahopower.com/heatingcooling.

SCHEDULE 72
HEATING AND COOLING
EFFICIENCY PROGRAM
(Continued)

INCENTIVE STRUCTURE (Continued)

Equipment/Service	Eligibility Requirements	Participant Incentive	Contractor Incentive	Notes
High Efficiency Air Source or Open Loop Water Source Heat Pump: Proper Sizing & Installation	Replacing an Existing Heat Pump			
	8.2 HSPF	$200	$150	1,2
	8.5 HSPF	$250	$150	1,2
	Minimum 3.5 COP	$500	$150	1,2
	Replacing an Existing Electric, Oil or Propane Heating System			
	8.2 HSPF	$300	$150	1,3
	8.5 HSPF	$400	$150	1,3
	Minimum 3.5 COP	$1,000	$150	1,3
Evaporative Cooler: Purchase & Installation	Unit must be equal to or greater than 2500 CFM	$150	n/a	1

Notes:

1. Existing single and multi-family site-built and manufactured homes.
2. Must replace an existing air source heat pump. First-time installations do not qualify.
3. Must replace an oil/propane heating system or be installed in new construction homes in areas where natural gas is not available.

QUALIFICATIONS

In order to receive a financial incentive under this program, each participating customer must complete the following steps

1. Select a participating company.
2. Purchase high efficiency equipment that meets program requirements.
3. Have participating company properly size and install qualified equipment according to program requirements.
4. Complete and sign the customer portion of the incentive application supplied by the participating company. The participating company will submit the application paperwork on the customer's behalf.

SCHEDULE 73
HOME PRODUCTS PROGRAM
(OPTIONAL)

AVAILABILITY

This program is available to residential customers living in single and multi-family residences, including manufactured and modular homes, who purchase qualified ENERGY STAR® home products and install them in a home within the Company's service territory within the State of Oregon.

APPLICABILITY

Service under this schedule applies to the purchase of qualified new clothes washers, refrigerators, light fixtures, ceiling fans with light kits, or ceiling fan light kits that are certified as an ENERGY STAR® product. ENERGY STAR® is a government-backed program that designates products as energy efficient. Products labeled as ENERGY STAR® must meet higher, stricter energy efficiency criteria than federal standards. ENERGY STAR® qualified home products use advanced technologies and consume 10-50 percent less energy.

PROGRAM DESCRIPTION

The Home Products Program is an incentive-based program designed to help cover a portion of the costs of purchasing qualified energy efficient clothes washers, refrigerators, light fixtures, ceiling fans with light kits, or ceiling fan light kits.

INCENTIVE STRUCTURE

To be eligible for an incentive, purchase and installation of the qualifying products cannot have started prior to July 30, 2008.

Equipment Category	Incentive per Unit	Notes
Clothes Washers	$50	1
Refrigerators	$30	2
Light Fixtures	$15	1
Ceiling Fans with Light Kits	$20	1
Ceiling Fan Light Kits	$20	1

Notes:

1) To view a list of the qualified ENERGY STAR® home products included in this equipment category, visit www.energystar.gov.

2) Only full-size refrigerators 7.75 cubic feet or larger are eligible for incentives. Although freezers and compact refrigerators are listed along with qualified full-size refrigerators on the ENERGY STAR® website, incentives are only available for the refrigerators.

SCHEDULE 73
HOME PRODUCTS PROGRAM
(OPTIONAL)

QUALIFICATIONS

In order to receive a financial incentive under this program, each participating customer must complete the following steps:

1. Purchase and install a new qualified ENERGY STAR® home product.

2. Complete the Idaho Power Home Products Incentive Application and sign it.

3. Mail the completed incentive form and a copy of the itemized sales receipt to Idaho Power.

SCHEDULE 74
RESIDENTIAL AIR CONDITIONER CYCLING PROGRAM
(OPTIONAL)

PURPOSE

The Residential Air Conditioner Cycling Program is an optional, supplemental service that permits participating residential Customers an opportunity to voluntarily allow the Company to cycle their central air conditioners with the use of a direct load control Device installed at their residence. Customers will receive a monthly monetary incentive for successfully participating in the Program during the Air Conditioning Season.

DEFINITIONS

AC Cycling is the effect of the Company sending a signal to a Device installed at the Customer's residence and instructing it to cycle the Central Air Conditioning compressor for a specified length of time.

Air Conditioning Season is the three-month period that commences on June 1 and continues through August 31 of each calendar year.

Central Air Conditioning is a home cooling system that is controlled by one or more centrally located thermostats that controls one or more refrigerated air-cooling units located outside the Customer's residence.

Cycling Event is a period during which the Company sends a signal to the Device installed at the Customer's residence, which instructs the Device to begin AC Cycling.

Device is a direct load control device installed at a Customer's residence that enables the Company to initiate AC Cycling.

Notification refers to the Customer's indication of intent to initiate or terminate participation in the Program by either contacting the Company's Customer Service Center, providing written notice or submitting an electronic Application via the Company's website.

Opt Out is the term used to describe the one-day per month during each month of the Air Conditioning Season in which the Customer may choose to temporarily not participate in AC Cycling by providing advanced Notification to the Company.

Program Operation Area describes the area in which the Program will be offered to Customers and is comprised of the Company's service territory within the State of Oregon where the infrastructure required to support AC Cycling has been installed and is operational.

SCHEDULE 74
RESIDENTIAL AIR CONDITIONER
CYCLING PROGRAM
(OPTIONAL)
(Continued)

AVAILABILITY

Service under this schedule is available on an optional basis to Customers taking service under Schedule 1 who have Central Air Conditioning located at their residences and live within the Program Operation Area. Customers may request to be added to the Program at any time during the year by providing Notification to the Company.

Service under this schedule may be limited based upon the availability of Program equipment and/or funding. The Company shall have the right to select and reject Program participants at its sole discretion based on criteria the Company considers necessary to ensure the effective operation of the Program. Selection criteria may include, but will not be limited to, energy usage, residential location, size of home, or other factors. Customers' Central Air Conditioning equipment must be fully functional and comply with the National Electric Code (NEC) standards. Customers who are renting or leasing their home must provide to the Company written proof of the express permission of the owner of the Central Air Conditioning system prior to acceptance into the program.

TERMS AND CONDITIONS

Upon acceptance into the Program, Customers will be subject to the following terms and conditions:

1. Each eligible Customer who chooses to take service under this optional schedule is thereby giving the Company or its representative permission, on reasonable notice, to enter the Customer's residence or property to install a Device and, in certain cases, either a mass memory meter or an end-use meter and to allow Idaho Power or its representative, with prior notice to the Customer, reasonable access to the Device or other Program-related equipment following its installation.

2. Customers added to the Program during the Air Conditioning Season must be effectively participating in the Program prior to the 20th day of the month in order to receive an incentive payment for that initial month.

3. A Customer may Opt Out of the Program for one day per month during each month of the Air Conditioning Season.

4. A Customer may discontinue participation in the Program without penalty by providing Notification to the Company.

5. If there is evidence of alteration, tampering, or otherwise interfering with the Company's ability to initiate a Cycling Event, the Customer's participation in the Program will be terminated and the Customer will be required to reimburse the Company for the cost of replacement or repair of the Device or other Program equipment and the Company will reverse any amounts credited to the Customer's bills during the past twelve months as a result of the Customer's participation in the Program.

SCHEDULE 74
RESIDENTIAL AIR CONDITIONER
CYCLING PROGRAM
(OPTIONAL)
(Continued)

PROGRAM DESCRIPTION

1. At the Company's expense, the Company or its representative will install a Device at the Customer's residence.

2. A financial incentive of $7.00 per month for each of the three months of the Air Conditioning Season will be paid to each Customer who successfully participates in the Program. This incentive will be paid in the form of a credit on the Customer's monthly bill for each month that the Customer successfully participates in the Program, beginning with the July bill and ending with the September bill. Incentive payments are limited to one controlled Central Air Conditioning unit per metered service point. Customer's who have more than one Central Air Conditioning unit at a metered service point may participate in the Program. A Device must be installed at each Central Air Conditioning unit. However, no additional incentive will be paid.

3. The Company will send a signal to the Device to initiate a Cycling Event. A Cycling Event may be up to four hours per day on any weekday during the Air Conditioning Season. A Cycling Event may occur over a continuous 4-hour period or may be segmented throughout the day at the Company's discretion in order to optimize available resources. Cycling Events may occur up to 40 hours each month and will not exceed a total of 120 hours per Air Conditioning Season. Mass memory meters or end-use meters may be installed on some Customers' residences or Central Air Conditioning units for program evaluation purposes. The residences or Central Air Conditioning units selected for installation of the meter shall be at the Company's sole discretion.

SPECIAL CONDITIONS

The Company is not responsible for any consequential, incidental, punitive, exemplary or indirect damage to the participating Customer or third parties that results from AC Cycling, from the Customer's participation in the Program, or of Customer's efforts to reduce peak energy use while participating in the Program.

The Company makes no warranty of merchantability or fitness for a particular purpose with respect to the Device and any and all implied warranties are disclaimed.

The Company shall have the right to select the AC Cycling schedule and the percentage of Customers' Central Air Conditioning systems to cycle at any one time, up to 100%, at its sole discretion.

The provisions of this schedule do not apply for any time period that the Company interrupts the Customer's load for a system emergency or any other time that a Customer's service is interrupted by events outside the control of the Company. The provisions of this schedule will not affect the calculation or rate of the regular Service or Energy Charges associated with a Customer's standard service schedule.

SCHEDULE 75
CHANGE A LIGHT PROGRAMS

This schedule describes the "Change a Light" Programs offered by the Company and funded by the Energy Efficiency Rider.

SPIRAL BULB PROGRAM

AVAILABILITY

This program is available to customers purchasing designated, reduced-price ENERGY STAR® light bulbs from participating retailers. Bulbs can be purchased as available on a first-come, first-served basis. The program will be effective from September 10, 2008 through December 31, 2010 or until the bulbs for the program are exhausted, whichever is earlier.

SERVICE PROVIDED

Designated ENERGY STAR® light bulbs range from 13-30 watts. Using the Energy Efficiency Rider funds, the Company will pay Fluid Market Strategies, Inc. for manufacturers' mark-down fees plus their program administration costs. The bulbs will be distributed to participating retailers and sold for a price of $1.00 per bulb. Fluid Market Strategies, Inc. will be responsible for manufacturer negotiations, retailer relationships, product pricing, sales data tracking and in-store marketing. The Company will augment in-store promotions and perform additional in-store visits, where possible.

SPECIALITY BULB PROGRAM

AVAILABILITY

This program is available to customers purchasing designated, reduced-price ENERGY STAR® light bulbs from participating retailers. Bulbs can be purchased as available on a first-come, first-served basis. The program will be effective from July 1, 2009 through September 30, 2009 or until the bulbs for the program are exhausted, whichever is earlier.

SERVICE PROVIDED

Designated ENERGY STAR® light bulbs have varying wattages but may include recessed cans, globes, three-way bulbs, dimmable, outdoor and specialty spirals. Using the Energy Efficiency Rider funds, the Company will pay Portland Energy Conservation, Inc. for manufacturers' mark-down fees plus their program administration costs. The bulbs will be distributed to participating retailers. Portland Energy Conservation, Inc. will be responsible for manufacturer negotiations, retailer relationships, product pricing, sales data tracking and in-store marketing. The Company will augment in-store promotions and perform additional in-store visits, where possible.

SCHEDULE 77
ENERGY STAR®
HOMES NORTHWEST

AVAILABILITY

Service under this schedule is available to building contractors that construct onsite, single-family homes within the Company's Oregon service territory that will take residential service under Schedule 1 upon completion.

APPLICABILITY

Service under this schedule applies to new site-built construction of single-family homes that have been certified to the ENERGY STAR Homes Northwest Builder Option Package (BOP) specification.

PROGRAM DESCRIPTION

ENERGY STAR Homes Northwest is an incentive-based program that encourages the onsite construction of energy efficient single-family homes. The Company provides a $750 incentive to building contractors whose homes include central air conditioning and meet the qualifications of ENERGY STAR Homes Northwest. The ENERGY STAR Homes Northwest BOP specification is based upon the building standard developed by the Environmental Protection Agency and the US Department of Energy through support from the Northwest Energy Efficiency Alliance (the Alliance). Through a cooperative effort with the Alliance, the Company will also provide education and information about energy efficient home construction to building contractors and consumers.

QUALIFICATIONS

Each participating building contractor must complete and sign an ENERGY STAR Homes Northwest Program Single-Family Builder Agreement and provide an IRS form W-9 to the Company. In order to receive a financial incentive under this program, a building contractor must complete the following steps for each home:

1. Submit a completed Project Initiation Form.

2. Upon the completion of construction, provide documentation that verifies a State Certifying Organization (SCO) registered with the Alliance has certified the home. Documentation from the SCO must include verification that the home has been constructed to the ENERGY STAR Homes Northwest BOP specification and that the central air conditioning system has been properly commissioned by a certified heating and cooling systems technician.

SCHEDULE 78
RESIDENTIAL ENERGY CONSERVATION PROGRAM

AVAILABILITY

This schedule is available throughout the Company's service area within the State of Oregon to residential Customers who qualify for the Residential Energy Conservation Program.

DEFINITIONS

Cash Payment means a payment made by the Company to the dwelling owner or to the contractor on behalf of the dwelling owner for energy conservation measures.

Commission means the Oregon Public Utility Commission.

Cost-Effective means that an energy conservation measure that provides or saves a specific amount of energy during it's life cycle results in the lowest present value of delivered energy costs of any available alternative. However, the present value of the delivered energy costs of an energy conservation measure shall not be treated as greater than that of a non-conservation energy resource or facility unless that cost is greater than 110 percent of the present value of the delivered energy cost of the non-conservation energy resource or facility.

Dwelling means real or personal property within the state inhabited as the principal residence of a dwelling owner or a tenant including a mobile home, a floating home and a single unit in multiple-unit residential housing, but not a recreational vehicle.

Dwelling Owner means the person who has legal title to a dwelling, including the mortgagor under a duly recorded mortgage of real property, the trustor under a duly recorded deed of trust or a purchaser under a duly recorded contract for the purchase of real property, and whose dwelling receives space heating from the Company.

Eligible Customer means any Customer receiving residential service. Responsibility for furnishing the energy audit lies within the utility providing the primary source of space heating energy. If the Company is not the primary supplier of space heating energy, it may discharge its energy audit obligation by arranging for the primary supplier of space heating energy to perform the energy audit.

Energy Audit means:

1. The measurement and analysis of the heat loss and energy utilization efficiency of a dwelling.

2. An analysis of the energy savings in mills per kWh and dollar savings potential that would result from providing energy conservation measures for the dwelling.

3. An estimate of the cost of the energy conservation measures including labor for the installation of items designed to improve the space heating and energy utilization efficiency of the dwelling and the items installed.

4. A determination of whether the energy conservation measure is cost effective.

SCHEDULE 78
RESIDENTIAL ENERGY CONSERVATION
PROGRAM
(Continued)

DEFINITIONS (Continued)

5. A preliminary assessment, including feasibility and a range of costs, of the potential and opportunity for installation of passive solar space heating and solar domestic water heating in the dwelling, and solar swimming pool heating, if applicable.

Energy Conservation Measures means measures that include the installation of items and the items installed to improve the space heating and energy utilization efficiency of a dwelling. These items include but are not limited to, caulking, weatherstripping and other infiltration preventative materials, ceiling insulation, crawl space insulation, vapor barrier materials, timed thermostats (except when used with heat pumps), insulation of heating ducts, hot water pipes and water heaters in unheated spaces, storm doors and windows and double glazed windows. Energy Conservation Measures does not include the dwelling owner's own labor.

Residential Customer means dwelling owner or tenant who is billed by the Company for electric service received at the dwelling.

Residential Space Heating Customer means a residential Customer who uses electricity as the primary source of space heating.

Space Heating means the heating of living space within a dwelling.

Tenant means a tenant as defined in ORS 91.705 or any other tenant.

NOTIFYING CUSTOMER OF PROGRAM

Upon approval by the Commission of the Company's Residential Energy Conservation Program, the Company shall promptly implement the program by sending a notice described in this section to all its Residential Customers and shall give similar notice at least once every year thereafter.

The Company will mail to a dwelling owner an offer to provide financing for Energy Conservation Measures when a tenant who is a residential space heating Customer requests that the offer be mailed to the dwelling owner, and furnishes the dwelling owner's name and address with the request.

The Notice Shall Set Forth:

1. That assistance and technical advice regarding energy conservation is available from the Company including an energy audit of a dwelling without direct charge if requested by the Residential Customer.

2. That financing for Energy Conservation Measures is available from the Company to an eligible dwelling owner in the form of a loan or cash payment.

3. That provides an address and telephone number that the Customer can call to obtain these services from the Company.

SCHEDULE 78
RESIDENTIAL ENERGY CONSERVATION
PROGRAM
(Continued)

ENERGY AUDIT

The Company will provide, within 60 days of a request by a residential space heating Customer or a dwelling owner, assistance and technical advice concerning various methods of saving energy in that Customer's or dwelling owner's dwelling, including, but not limited to an energy audit.

The energy audit shall include:

1. The measurement and analysis of the heat loss and energy utilization efficiency of a dwelling.

2. An analysis of the energy savings in mills per kWh and dollar savings potential that could result from providing Energy Conservation Measures for the dwelling.

3. An estimate of the cost of the Energy Conservation Measures including labor for the installation of items designed to improve the space heating and energy utilization efficiency of the dwelling excluding the dwelling owner's own labor, and the items installed.

4. A determination of whether the Energy Conservation Measure is cost-effective.

5. A preliminary assessment, including feasibility and a range of costs, of the potential and opportunity for installation of passive solar space heating and solar domestic water heating in the dwelling and solar swimming pool heating, if applicable.

If the dwelling requested to be audited is a rental unit, the audit shall include a heating cost estimate using average temperatures and typical lifestyles. A statement shall be included to the effect that a household's energy bill will contain charges for uses in addition to space heating. Such heating cost estimate and statement shall be displayed on the audit or a separate document suitable for conspicuous posting.

Upon a dwelling owner's request, the Company will provide information relative to the specific site of a dwelling with access to water resources that have hydroelectric potential, wind (which means the natural movement of air at an annual average speed of at least 8 miles an hour) and a resource area known to have geothermal space heating potential.

If sufficient data is not available to provide a valid audit based upon normal energy consumption, the Company shall make a reasonable estimate of such consumption for the purpose of completing the audit.

COST-EFFECTIVENESS GUIDELINE

"Cost-effective", as defined in Oregon Laws 1981, Chapter 778, relates an Energy Conservation Measure's cost, life cycle and the cost of alternative energy facilities.

SCHEDULE 78
RESIDENTIAL ENERGY CONSERVATION
PROGRAM
(Continued)

COST-EFFECTIVENESS GUIDELINE (Continued)

The following Energy Conservation Measures are determined to be always cost-effective:

1. Caulking
2. Weatherstripping
3. Ground cover, when installed in conjunction with under-floor insulation
4. Vapor barrier materials, when installed in conjunction with wall, ceiling, or under-floor insulation
5. Timed (set-back) thermostats (except when used with heat pumps)
6. Water heater, steam pipe, hot and cold water pipe-wraps
7. Dehumidifiers, when installed in conjunction with storm windows and doors, and caulking and weatherstripping of all openings allowing infiltration
8. Attic ventilation, excluding power ventilators, when installed in conjunction with ceiling insulation

The following Energy Conservation Measures shall be deemed to have the following life cycles:

1. Attic, ceiling, wall and under-floor insulation: 30 years
2. Insulation of walls in heated basements: 30 years
3. Insulation of heating system supply and return air ducts: 30 years
4. Thermal doors: 30 years
5. Storm windows: 15 years
6. Replacement windows meeting the requirements of Chapter 53 of the Oregon Residential Energy Code: 25 years
7. Storm doors: 7 years

COST-EFFECTIVE COMPUTATIONS

Energy Conservation Measures having an expected life cycle of 7 years shall be considered Cost-Effective if the installed cost is less than $0.44 per annual kWh saved. Energy Conservation Measures having an expected life cycle of 15 years, 25 years, and 30 years shall be considered Cost-Effective if the installed cost is less than $0.76 per annual kWh saved, $1.03 per annual kWh saved, and $1.12 per annual kWh saved, respectively.

SCHEDULE 78
RESIDENTIAL ENERGY CONSERVATION
PROGRAM
(Continued)

FINANCING

The Company will provide financing for Energy Conservation Measures at the request of a dwelling owner who occupies the dwelling as a residential space heating Customer or rents the dwelling to a tenant who is a residential space heating Customer if the dwelling has an electrical space heating system, installed and operational, which is designed to heat the living space of the dwelling. The financing program shall give the eligible dwelling owner a choice between a cash payment or a loan. As a condition of eligibility for either a cash payment or a loan, an Energy Audit of the dwelling will be required in order to determine which Energy Conservation Measures are Cost-Effective.

The Company will offer to all qualifying owners a choice between the following levels of assistance:

COST EFFECTIVE MEASURES

1. A loan by the Company not to exceed $5,000, upon approved credit, to be used to pay for the Energy Conservation Measures over a period of time not to exceed 10 years. Minimum monthly payment will be $15. Interest will be paid at a 6½ percent annual rate for the cost of those measures, or a portion of the cost thereof, which are in accordance with the Cost-Effectiveness criteria of this schedule; or

2. A cash payment to the dwelling owner for 25 percent of the Cost-Effective portion of the Energy Conservation Measures recommended, including installation (but not including the dwelling owner's own labor), not to exceed the cost of the measure, up to a maximum cash payment of $1,000.

If the dwelling is a rental unit, the following additional assistance is available to qualifying dwelling owners beginning in the tax year after December 31, 1985:

1. If the loan under 1 above is selected, the dwelling owner shall be liable to repay to the utility the loan amount minus the present value of the tax credits to Idaho Power established pursuant to ORS 469.185 to 469.225; or

2. If the cash payment under 2 above is selected, the cash payment shall be supplemented by an amount equal to the present value of the tax credits to Idaho Power established pursuant to ORS 469.185 to 469.225.

NON COST EFFECTIVE MEASURES

1. A loan arranged or issued by the Company for the non Cost-Effective portion of Energy Conservation Measures not to exceed the difference between $5,000 and the amount loaned under paragraph 1 above. Measures over a period of time not to exceed 10 years. Interest will be paid at the annual rate established by the Public Utility Commission of Oregon and the minimum monthly payment will be $15.

SCHEDULE 78
RESIDENTIAL ENERGY CONSERVATION
PROGRAM
(Continued)

FINANCING (Continued)

An eligible dwelling owner may obtain up to $5,000 in loans or $1,000 in cash payments for each dwelling. For any dwelling, whenever the combined interest rate computed for both Cost-Effective and Non Cost-Effective measures financed under this schedule exceeds 12 percent, the interest rate for the loan financing the Non Cost-Effective measures shall be recomputed so that the combined rate for the two loans equals 12 percent.

A dwelling owner who acquires a dwelling for which a previous loan was obtained under the program may obtain a loan or cash payment for Energy Conservation Measures for the newly acquired dwelling under circumstances including, but not necessarily limited to, when (a) the new dwelling owner chooses the same financing option chosen by the previous dwelling owner who obtained financing under this program; and (b) there remain Cost-Effective Energy Conservation Measures to be undertaken with regard to the dwelling. Provided, however, there may be no more than two loans or cash payment for each dwelling.

No cash payment shall be allowed or paid for the cost of Energy Conservation Measures provided more than one year before the date of the application for payment.

The Company shall charge or bill a dwelling owner on the periodic utility bill for the loan repayment of those Energy Conservation Measures installed.

A dwelling owner served by the Company who applies for financing of Energy Conservation Measures, may use an Energy Audit obtained from the Company under Oregon Laws, 1977, Chapter 889, before November 1, 1981, without obtaining a new energy audit.

Energy Conservation Measures installed in conjunction with construction of a new dwelling or construction which increases or otherwise changes the living space in the dwelling such as an addition, substantial alteration or remodeling, shall not be financed under the financing program.

CREDIT APPLICATIONS AND SECURITY FOR LOANS

Dwelling owners who desire loan financing will complete and sign a credit application. The Company will investigate credit applications in-house or through commercial credit rating bureaus and shall approve or reject applications. If credit is approved by the Company, the dwelling owner shall sign a promissory note in an amount not to exceed the cost of the Energy Conservation Measures, which promissory note shall bear interest at the rate or rates specified above. The Company will prepare and provide all documents necessary to complete financing arrangements.

OTHER SERVICES

The Company shall verify through post-installation inspections that Energy Conservation Measures financed by the Company are installed in a workmanlike manner.

The Company shall not disburse any funds used for principal payment until such post-installation inspections have been completed.

SCHEDULE 79
WEATHERIZATION ASSISTANCE FOR QUALIFIED CUSTOMERS PROGRAM

AVAILABILITY

Service under this schedule is available to agencies throughout the Company's service area within the State of Oregon participating in the Low Income Weatherization Assistance Program administered by the Oregon Housing & Community Services Department. Service under this schedule is subject to the provisions of the signed Agreement between the agency and the Company.

APPLICABILITY

Service under this schedule is applicable to qualifying energy conservation measures installed in single- and multi-family residential dwellings, including mobile homes, which have permanently wired electric space heating of 5 watts or more per square foot. Service is also applicable to qualifying energy conservation measures installed in buildings which have permanently wired electric space heating of 5 watts or more per square foot, which are occupied by private, non-profit organizations which serve primarily low-income clientele, and which have obtained a 501(c)(3) tax exempt status. Energy conservation measures installed must meet the qualifying specifications of the Low Income Weatherization Assistance Program administered by the Oregon Housing and Community Services Department. Qualifying energy conservation measures are those specified in the Low Income Weatherization Assistance Plan, except that repair or replacement of fossil fuel furnaces and installation of plastic window coverings do not qualify under this schedule.

GRANTS TO AGENCIES

The Company will determine the amount of annual grant funds available to each participating agency each year in accordance with the provisions of the Agreement. Funds will be distributed to a participating agency upon demonstration by the agency that qualifying conservation measures have been installed in a dwelling. Grant funds made available to an agency but not distributed to that agency during the current year may be carried forward to the next year.

The Company grant funds may be used to fund up to 85 percent of the total cost of qualifying conservation measures installed in a dwelling provided at least 15 percent of the total cost of qualifying conservation measures is funded by the Department of Energy.

Non-Profit 501(c)(3) Buildings: The Company will make funds available for the installation of weatherization measures in qualifying non-profit 501(c)(3) buildings in accordance with the provisions of the Agreement. The Company funds may be used to fund up to 100 percent of the total cost of qualifying conservation measures.

In addition to weatherization funds, the Company will provide to each agency an administrative payment equal to 10 percent of the portion funded by the Company for each dwelling or building for which weatherization was completed with the assistance of Company funds.

SCHEDULE 80
EASY UPGRADES PROGRAM

AVAILABILITY

Service under this schedule is available to commercial and industrial Customers throughout the Company's service area within the State of Oregon taking service under Schedule 7, Schedule 9, or Schedule 19.

APPLICABILITY

This schedule is applicable to electric energy efficiency retrofit projects typical of commercial or industrial applications that meet the requirements of the Easy Upgrades Program.

PROGRAM DESCRIPTION

The Easy Upgrades Program is an incentive-based program designed to help cover a portion of the costs of installing energy efficiency features into existing commercial and industrial buildings. The Easy Upgrades Program uses a prescriptive approach to provide incentives for six general energy efficiency project categories: lighting and lighting controls, heating ventilation and air conditioning (HVAC) systems, motors and motor controls, building shell, plugs loads, and retail display refrigeration.

DEFINITIONS

British Thermal Unit. A measure of energy, referred to as BTU, which allows comparisons of disparate buildings, equipment types and/or fuel sources. As BTU/hour (BTUH) it refers to the energy over time which becomes the basis for equipment sizing and efficiency measurements.

Case. Refrigerated display case typically found in grocery stores. Refrigeration cases can be low temperature (for frozen products) or medium temperature (for refrigerated products). Cases can be open upright, enclosed by glass doors, or coffin cases that are open on the top.

Delamping. The permanent removal of fluorescent lamps during a lighting retrofit project. This can be achieved by a one-for-one retrofit where the installed fixture has fewer lamps than were previously in place. Delamping can also be achieved through a retrofit project that replaces old fixtures on a less than one-for-one basis.

Economizer. A feature of air conditioning units that relies on the "free cooling" effect of outside air during the cooler part of the year and/or day to minimize the need for the compressor's operation to generate mechanical cooling.

Energy Management System. A control technology that uses a series of sensors and computer logic to manage the energy use of an entire building or some subset of the building including, but not limited to, the HVAC system, lighting, and commercial or industrial refrigeration.

SCHEDULE 80
EASY UPGRADES PROGRAM
(Continued)

DEFINITIONS (Continued)

Fixture. An integral lighting system that consists of the lamp(s), ballast(s), and the housing that results in a self-contained source of illumination when supplied with electricity.

HVAC System. The equipment that provides a building's heating, ventilation, and air conditioning. HVAC equipment includes air conditioning units, boilers, chillers, cooling towers, furnaces, heat pumps, and other related components.

Incentive. Financial payment provided by Idaho Power to program participants to help cover a portion of the costs of installing or implementing energy efficiency measures.

Measure. Energy efficient features including, but not limited to, replacement equipment, added building materials, control features, systems or processes.

Occupancy Sensor. A technology used to sense the presence of people in an area and control lighting, setback thermostat settings, or even plug loads according to the areas occupancy status. The occupancy sensor turns on controlled equipment when it senses that people are present and turns off equipment when the presence of people is not sensed resulting in electricity savings.

Retrofit. The replacement of existing building materials or equipment, or the addition of controls or other devices through measures that increase the efficiency of building systems or processes.

Site. A single location taking electric service at one or more metered service points.

Ton. The measure of the output of cooling equipment for air conditioning or refrigeration. A ton of cooling capacity is equal to 12,000 BTUH.

INCENTIVE STRUCTURE

To be eligible for an incentive, installation of the qualifying equipment cannot have started prior to May 1, 2007. Installed measures must meet the requirements of the Easy Upgrades Program as detailed in Tables 1 through 6. Incentives will not be paid for measures required by Oregon code, mandated by federal standards, or otherwise required. Incentive payments will not exceed 100% of the installed cost for any specified measure. Eligible projects are subject to a maximum incentive cap of $100,000 per site per year.

SCHEDULE 80
EASY UPGRADES PROGRAM
(Continued)

INCENTIVE STRUCTURE (Continued)

TABLE 1: LIGHTING AND LIGHTING CONTROLS				
Equipment category	Installing	Replacing	Incentive Per Unit	Notes
T8 Fluorescents	1- or 2-lamp 4' T8 fixture	1- or 2-lamp 4' T12 fixture	$14.00	1
	3-lamp 4' T8 fixture	3-lamp 4' T12 fixture	$24.00	1
	4-lamp 4' T8 fixture	4-lamp 4' T12 fixture	$32.00	1
	2-lamp 8' T8 fixture	2-lamp 8' T12 fixture	$26.00	1
	2-lamp 8' T8 HO fixture	2-lamp 8' T12 HO fixture	$46.00	1, 2
	4-lamp 4' T8 High Bay fixture	Fixture drawing 250W or more	$80.00	1
	6-lamp 4' T8 High Bay fixture	Fixture drawing 400W or more	$120.00	1
	8-lamp 4' T8 High Bay fixture	Fixture drawing 750W or more	$190.00	1
	Low wattage T8 lamps	Standard wattage T8 lamps	$0.50	9
T5 Fluorescents	1- or 2-lamp 4' T5 fixture	1- or 2-lamp 4' T12 fixture	$14.00	1
	3-lamp 4' T5 fixture	3-lamp 4' T12 fixture	$24.00	1
	4-lamp 4' T5 fixture	4-lamp 4' T12 fixture	$30.00	1
	2-lamp 4' T5 HO fixture	4-lamp 4' T12 fixture	$28.00	1, 2
	3-lamp 4' T5 HO fixture	Fixture drawing 250W or more	$50.00	1, 2
	4-lamp 4' T5 HO fixture	Fixture drawing 400W or more	$90.00	1, 2
	6-lamp 4' T5 HO fixture	Fixture drawing 400W or more	$60.00	1, 2
Fluorescent Delamping	Delamping fixtures	In a T12 fixture to T8 or T5 retrofit	$12.00	1, 3
Metal Halide (MH) Lighting	30-70W efficient MH fixture	Fixture drawing at least 20W more	$18.00	1, 4
	70-150W efficient MH fixture	Fixture drawing at least 25W more	$22.00	1, 4
	150-250W efficient MH fixture	Fixture drawing at least 40W more	$26.00	1, 4
	250-360W efficient MH fixture	Fixture drawing at least 80W more	$55.00	1, 4
	360-500W efficient MH fixture	Fixture drawing at least 120W more	$75.00	1, 4
	500W+ efficient MH fixture	Fixture drawing at least 200W more	$105.00	1, 4
Lighting Controls	Occupancy sensor, wall/ceiling	Manual light switch	$40.00	
	Photocell dimming control	No prior control	$40.00	4
	Integral occupancy sensor	Manual switches or no control	$0.10	5
	Auto-off time switch	Controlling 100W or more	$20.00	
	Time clock control	No prior control	$20.00	
Compact Fluorescents (CFL) or Light Emitting Diodes (LEDs)	Screw-in lamp (25W or less)	Fixture drawing 40W or more	$2.00	6, 10
	Screw-in lamp (over 25W)	Fixture drawing 100W or more	$4.00	6, 10
	CFL or LED hardwired fixture	Incandescent or other fixture	$15.00	6, 10
Sign Lighting	LED or equivalent exit sign	Incandescent or fluorescent exit sign	$15.00	
	LED or equivalent exit sign	Marquee/Sign lighting	$15.00	7
Holiday Lights	LED lights	Incandescent T1¾ "mini" Incandescent C7 or 9	$0.10 $0.30	8

SCHEDULE 80
EASY UPGRADES PROGRAM
(Continued)

INCENTIVE STRUCTURE (Continued)

Table 1 Notes:

1) Incentive amount is based on energy-saving projections assuming lighting operation of 3,000 hours per year.

2) HO refers to high output fluorescent lighting fixtures.

3) The fluorescent delamping incentive is additive to the applicable lighting retrofit incentive. The T8 and T5 retrofits incentives are based on a lamp for lamp replacement. The delamping "bonus" also applies when the number of lamps installed is less than the number removed.

4) Applicable lighting systems are limited to building-connected fixtures. Non building-connected lighting, such as area or parking lot light fixtures, are not eligible.

5) Integral occupancy sensor incentive is based on the building floor area, in square feet, lit by the controlled lighting system.

6) Any CFL receiving a retail buy-down financed in whole or in part by Idaho Power are not eligible.

7) Marquee/sign lighting incentive is based on the sign dimensions, in square feet, of the sign retrofit.

8) Incentives will be paid per incandescent bulb retired, not to exceed the total price paid for new LED replacement bulbs. LED bulbs must replace holiday lights that are powered by a metered service connection.

9) Low-wattage T8 lamps are those with a nominal lamp wattage of 30W or less. This incentive applies as an adder when these lamps are installed as part of a T12 to T8 system retrofit. It can also apply to existing T8 systems that are relamped with low-wattage T8s.

10) LED screw-in lamps or hardwired fixtures are treated the same as CFLs for these incentives.

SCHEDULE 80
EASY UPGRADES PROGRAM
(Continued)

INCENTIVE STRUCTURE (Continued)

TABLE 2: HVAC AND HVAC CONTROLS

Equipment category	Installing	Replacing	Incentive Per Unit	Notes
Air Conditioning (AC) Units	PTAC/PTHP unit, min 12 EER	Standard PTAC/PTHP unit	$50.00	7
	5 ton or less 1 phase unit, ≥ 14 SEER	Standard (std.)1-5 ton AC unit	$25.00	1
	5 ton or less 1 phase unit, ≥ 15 SEER	Std. 5 ton or less AC unit	$50.00	
	5 ton or less 1 phase unit, ≥ 16 SEER	Std. 5 ton or less AC unit	$75.00	
	5 ton or less 3 phase unit, ≥ 13 SEER	Std. 1-5 ton AC unit	$50.00	2
	5 ton or less 3 phase unit, ≥ 14 SEER	Std. 5 ton or less AC unit	$75.00	
	5 ton or less 3 phase unit, ≥ 15 SEER	Std. 5 ton or less AC unit	$100.00	
	6 - 10 ton AC unit, ≥ 11 EER	Std. 6 – 10 ton AC unit	$50.00	2
	11 - 19 ton AC unit, ≥ 10.8 EER	Std. 11 - 19 ton AC unit	$50.00	2
	20 ton or more AC unit, ≥ 10 EER	Std. 20 ton+ AC unit	$50.00	2
Economizers	Air side economizer control addition	No prior control	$75.00	
	Water side economizer control addition	No prior control	$75.00	
	Air side economizer control repair	Non-functional economizer	$250.00	3
Evaporative Coolers/Pre-Coolers	Pre-cooler added to condenser	Standard air cooled AC unit	$100.00	
	Retrofit to direct evaporative cooler	Replacing std. AC unit	$200.00	
	Retrofit to indirect evaporative cooler	Replacing std. AC unit	$300.00	
Variable Speed Fans/Pumps	Variable speed drive (VSD), fan	Single speed HVAC sys fan	$60.00	4
	Variable speed drive, pump	Single speed HVAC sys pump	$60.00	4
Programmable Thermostats	7-day, two-stage setback thermostat	Manual thermostat	$40.00	5
Automated Control Systems	Energy management control system	Manual controls	$0.30	6
	Control system reprogramming	Automated control system	$0.10	8
	Lodging room occupancy controls	Manual controls	$50.00	9

SCHEDULE 80
EASY UPGRADES PROGRAM
(Continued)

INCENTIVE STRUCTURE (Continued)

Table 2 Notes:

1) Qualifying efficiencies are based on specifications established by the Consortium for Energy Efficiency (CEE) in Tier 2 of the High Efficiency Commercial Air Conditioning and Heat Pump Initiative (HECAC) specifications.

2) Qualifying efficiencies are based on specifications established by the Consortium for Energy Efficiency (CEE) in Tier 1 of the High Efficiency Commercial Air Conditioning and Heat Pump Initiative (HECAC) specifications.

3) Economizer repair incentives are one-time and require an itemized invoice and documentation of repairs made. The per-unit incentive can not exceed the stated cost on the invoice.

4) VSD installations only apply to variably loaded fan and pump motors operating at least 2,000 hours per year. VSDs must be installed in accordance with Institute of Electrical and Electronics Engineers (IEEE) Standard 519.

5) Programmable thermostats must be commercial-grade, two-stage models with 7-day programmability and battery back-up. Three stage models are recommended when installed to control heat pump operation. Optimum start capabilities are also recommended.

6) Automated EMS control incentives are based on the building floor area, in square feet, of the HVAC system(s) controlled and are limited to $10,000 per site.

7) Packaged Terminal Air Conditioning (PTAC) and Packaged Terminal Heat Pump (PTHP) units are through-the-wall units of 15,000 BTUH cooling output or less, commonly used in lodging rooms.

8) Automated control system reprogramming to optimize energy performance are one-time and require itemized documentation of the programming changes made. The per-site incentive is limited to $2,500 and can not exceed the stated cost on the invoice.

9) Lodging room occupancy controls apply to any smart system that can sense when the room is unoccupied and turns the room HVAC unit off or adjusts accordingly.

SCHEDULE 80
EASY UPGRADES PROGRAM
(Continued)

INCENTIVE STRUCTURE (Continued)

TABLE 3: MOTORS AND MOTOR CONTROLS

Equipment category	Installing	Replacing	Incentive Per Unit	Notes
NEMA Premium Efficiency™ Motors	1 HP Motor, minimum 85.5% efficiency	Equal or larger size std. motor	$20.00	1
	1.5 HP Motor, minimum 86.5% efficiency	Equal or larger size std. motor	$25.00	1
	2 HP Motor, minimum 86.5% efficiency	Equal or larger size std. motor	$30.00	1
	3 HP Motor, minimum 89.5% efficiency	Equal or larger size std. motor	$35.00	1
	5 HP Motor, minimum 89.5% efficiency	Equal or larger size std. motor	$40.00	1
	7.5 HP Motor, minimum 91.7% efficiency	Equal or larger size std. motor	$55.00	1
	10 HP Motor, minimum 91.7% efficiency	Equal or larger size std. motor	$70.00	1
	15 HP Motor, minimum 93.0% efficiency	Equal or larger size std. motor	$90.00	1
	20 HP Motor, minimum 93.0% efficiency	Equal or larger size std. motor	$110.00	1
	25 HP Motor, minimum 93.6% efficiency	Equal or larger size std. motor	$130.00	1
	30 HP Motor, minimum 94.1% efficiency	Equal or larger size std. motor	$150.00	1
	40 HP Motor, minimum 94.1% efficiency	Equal or larger size std. motor	$180.00	1
	50 HP Motor, minimum 94.5% efficiency	Equal or larger size std. motor	$220.00	1
	60 HP Motor, minimum 95.0% efficiency	Equal or larger size std. motor	$280.00	1
	75 HP Motor, minimum 95.4% efficiency	Equal or larger size std. motor	$350.00	1
	100 HP Motor, minimum 95.4% efficiency	Equal or larger size std. motor	$420.00	1
	125 HP Motor, minimum 95.4% efficiency	Equal or larger size std. motor	$550.00	1
	150 HP Motor, minimum 95.8% efficiency	Equal or larger size std. motor	$650.00	1
	200 HP Motor, minimum 96.2% efficiency	Equal or larger size std. motor	$750.00	1
Downsizing Bonus	For downsizing motors during retrofit	10-200HP existing motor	$3.00	2
ECM Motors	Electronically Commutated Motor (ECM)	Standard Motor	$30.00	
Variable Speed Controls	Variable Speed Drives	100 HP Motor or less	$60.00	3

SCHEDULE 80
EASY UPGRADES PROGRAM
(Continued)

INCENTIVE STRUCTURE (Continued)

Table 3 Notes:

1) Any 1,800 rpm Open Drip Proof (ODP) or Totally Enclosed Fan Cooled (TEFC) that meet the NEMA Premium™ nominal full-load efficiency ratings are eligible. 1,200 and 3,600 rpm motors may be eligible based on a different efficiency rating. Refer to the applicable NEMA Premium™ nominal full-load efficiency ratings to determine eligibility. Motors must have a minimum expected run time of 2,000 hours per year to be eligible.

2) The motor downsizing bonus is additive to the applicable motor retrofit incentive. The motor retrofit incentives are based on a same size replacement. The downsizing bonus applies when the size of the motor installed is less than the one removed.

3) VSD installations only apply to variably loaded motors operating at least 2,000 hours per year. VSDs must be installed in accordance with IEEE Standard 519.

SCHEDULE 80
EASY UPGRADES PROGRAM
(Continued)

INCENTIVE STRUCTURE (Continued)

TABLE 4: BUILDING SHELL

Equipment category	Installing	Replacing	Incentive Per Unit	Notes
Premium Windows	Low U-value, SHGC, High VLT	Standard windows	$1.00	1, 2, 4
Efficient Windows	Low U-value, SHGC	Standard windows	$0.50	1, 2, 4
Window Shading	Adding window shade film	No film or other shading	$0.50	2, 4
	Adding window shade screen	No screen or other shading	$0.50	2, 4
Roll-Up Doors	Insulated door (min R4)	Uninsulated roll-up door	$0.05	5
	High-speed automatic door	Standard automatic door	$25.00	6
Reflective Roofing	Adding reflective roof treatment	Non-reflective low pitch roof	$0.05	2, 3, 4
Roof/Ceiling Insulation	Increase to R24 min. insulation	Insulation level, R11 or less	$0.10	2, 4
	Increase to R38 min. insulation	Insulation level, R11 or less	$0.20	2, 4
Wall Insulation	Increase to R11 min. insulation	Insulation level, R5 or less	$0.05	2, 4

Table 4 Notes:

1) Premium windows must be certified by the National Fenestration Rating Council (NFRC) and meet Commercial Window Initiative (CWI) specifications for U-value, solar heat gain coefficient (SHGC), and visible light transmittance (VLT). Efficient windows meet all the same criteria with the exception of VLT.

2) Incentive eligibility is limited to installation on air conditioned buildings that utilize central air conditioning systems or packaged terminal air conditioning (PTAC) units.

3) Qualifying roof treatment must be ENERGY STAR® rated and have a total initial solar reflectivity of at least 70%.

4) Building Shell incentives are based on the surface area, in square feet, of the measure installed.

5) Insulated roll-up doors with a minimum insulation R-value of 4 are eligible when installed serving a space with central mechanical air conditioning or PTAC systems and are based on the surface area, in square feet, of the measure installed.

6) High-speed automated doors (either roll-up or folding doors) that open or close with a speed of at least 24 inches per second are eligible when installed serving a cold storage facility and are based on the surface area, in square feet, of the measure installed.

SCHEDULE 80
EASY UPGRADES PROGRAM
(Continued)

INCENTIVE STRUCTURE (Continued)

TABLE 5: PLUG LOADS

Equipment category	Installing	Replacing	Incentive Per Unit	Notes
Vending Machines	ENERGY STAR® vending machine	Standard vending machine	$75.00	1
	Beverage machine control	Vending machine with no sensor	$75.00	
	Other cold product control	Vending machine with no sensor	$50.00	
	Non-cooled snack control	Vending machine with no sensor	$25.00	
Commercial Kitchen Equipment	ENERGY STAR® dishwasher	Standard dishwasher	$15.00	2
	Low temperature dish machine	Dish machine w/ electric booster	$75.00	3
	ENERGY STAR® refrigerator	Standard residential refrigerator	$30.00	
	Solid door refrigerator, 1 door	Commercial 1 door refrigerator	$70.00	5
	Solid door refrigerator, 2 door	Commercial 2 door refrigerator	$90.00	5
	Solid door refrigerator, 3 door	Commercial 3 door refrigerator	$140.00	5
	Solid door freezer, 1 door	Commercial 1 door freezer	$100.00	5
	Solid door freezer, 2 door	Commercial 2 door freezer	$150.00	5
	Solid door freezer, 3 door	Commercial 3 door freezer	$200.00	5
	Ice maker, up to 200 lbs/day	Standard ice maker of the same size	$100.00	6
	Ice maker, 200 lbs/day +	Standard ice maker of the same size	$150.00	6
Personal Computers	80Plus PC - desktop	Standard personal computer, desktop	$5.00	
	80Plus PC - server	Standard personal computer, server	$10.00	
	ENERGY STAR® PC	Standard personal computer	$10.00	4
	ENERGY STAR® Copier	Standard copier w/out idle/off control	$25.00	
	PC network power management	No central control software in place	$10.00	
	Flat panel LCD display	Standard cathode ray (CRT) display	$10.00	
	Occupancy sensor controls	Computers, other plug loads	$10.00	
Laundry Machines	High efficiency washer	Standard washer, electric HW	$25.00	
	High efficiency coin-op washer	Coin-op wash, without electric HW	$25.00	
	High efficiency coin-op washer	Coin-op washer, with electric HW	$200.00	

SCHEDULE 80
EASY UPGRADES PROGRAM
(Continued)

INCENTIVE STRUCTURE (Continued)

Table 5 Notes:

1) Both new and rebuilt refrigerated beverage vending machines that are ENERGY STAR® certified are eligible.

2) Qualifying installations must have electric water heating and be used for at least one full cycle per work week.

3) Qualifying products must be used in a commercial kitchen or other environment where they experience at least 24 wash/rise cycles per day. Incentive payments will be based on the load (in kW) of the electric booster heater removed.

4) Qualifying PCs must meet ENERGY STAR® Version 4.0 Tier 1 specifications for desktop computers and workstations that take effect on July 20, 2007.

5) Commercial solid door refrigerators and freezers must have built-in (packaged) refrigeration systems and be listed as Tier 1 or better on the Consortium for Energy Efficiency (CEE) Commercial Kitchens Initiative list of qualifying equipment.

6) To qualify, ice makers must be included on the CEE Commercial Kitchens Initiative listing of High Efficiency Ice Machines.

SCHEDULE 80
EASY UPGRADES PROGRAM
(Continued)

INCENTIVE STRUCTURE (Continued)

TABLE 6: GROGERY REFRIGERATION

Equipment category	Installing	Replacing	Incentive Per Unit	Notes
Refrigeration Cases	Efficient medium (med.) temperature (temp.) open case	Std. med. temp. open case	$20.00	1
	Efficient med. temp. reach-in	Std. med. temp. open case	$100.00	1
	Efficient low temp. reach-in	Std. low temp. reach-in	$150.00	1
	Efficient low temp. reach-in	Std. low temp. open case	$150.00	1
	Efficient low temp. reach-in	Std. low temp. coffin case	$55.00	1
	Vertical night covers	No covers present	$9.00	1
	Horizontal night covers	No covers present	$5.00	1
	Add refrigeration line insulation	No insulation present	$1.00	2
	Install door gasket – walk-in	No or damaged door gasket	$2.00	3
	Install door gasket – reach-in	Damaged door gasket	$1.00	3
	Install auto-closer – walk-in	No/damaged auto-closer, low temp.	$50.00	4
	Install auto-closer – reach-in	Damaged auto-closer, low temp.	$50.00	4
	Install auto-closer – walk-in	No/damaged auto-closer, med. temp.	$40.00	4
	Install auto-closer – reach-in	Damaged auto-closer, med. temp.	$40.00	4
	Install no heat glass doors	Std. low temp. reach-in	$50.00	4
	Add anti-sweat heat controls	Low/med. temp. case w/out controls	$20.00	4
Evaporator Fans	Add evaporator fan controls	Med. temp. walk-in with no controls	$25.00	5
	Install efficient evap fan motor	Med. or low temp. walk-in	$100.00	5
	Install controllable case fan motor	Standard, shaded-pole fan motors	$30.00	5
Compressors and Condensers	Efficient low temp. compressor	Standard low temp. compressor	$45.00	6
	Air cooled multiplex system	Stand alone air cooled display case	$300.00	6
	Evap cooled multiplex system	Stand alone evap cooled display case	$300.00	6
	Efficient air cooled condenser	Standard air cooled condenser	$100.00	6
	Efficient water cooled condenser	Standard air cooled condenser	$100.00	6
	Efficient evaporative condenser	Standard air cooled condenser	$200.00	6
Floating Head, Suction Pressures	Head pressure controller	Standard head pressure control	$60.00	7
	Suction pressure controller	Standard suction pressure control	$10.00	7
Case/Walk-In Lighting	T8 fluorescent lighting	T12 fluorescent lighting	$15.00	8
	LED display case lighting	T12 fluorescent lighting	$7.00	
	Fluorescent walk-in light fixture	Incandescent walk-in light fixture	$25.00	

SCHEDULE 80
EASY UPGRADES PROGRAM
(Continued)

INCENTIVE STRUCTURE (Continued)

Table 6 Notes:

1) The incentive basis for these measures is the length (in linear foot) of display cases replaced or retrofitted. The incentive will be based on the prior case length when the new case is longer than what was replaced.

2) The incentive basis for this measure is the length (in linear foot) of refrigeration line insulated.

3) The incentive basis for these measures is the length (in linear foot) of door perimeter gasketed.

4) The incentive basis for these measures is the number of doors affected.

5) The incentive basis for these measures is the number of fans or motors controlled or replaced.

6) The incentive basis for these measures is the tons of refrigeration capacity affected.

7) The incentive basis for this measure is the horsepower (HP) of compressors in the system.

8) Light Emitting Diodes (LEDs) used in refrigerated case lighting are provided an incentive based on a per-foot basis of the prior fluorescent display lighting that is removed.

SCHEDULE 81
CUSTOM EFFICIENCY PROGRAM

AVAILABILITY

Service under this schedule is available to commercial and industrial Customers throughout the Company's service area within the State of Oregon taking service under Schedules 9 and 19. This Schedule is also available to new commercial or industrial Customers that will take service under Schedules 9 or 19 upon completion of an applicable project.

APPLICABILITY

This schedule is applicable to electric energy efficiency projects typical of commercial or industrial applications that meet the requirements of the Custom Efficiency Program.

PROGRAM DESCRIPTION

The Custom Efficiency Program is an incentive based program designed to encourage commercial and industrial Customers to install equipment, systems, or processes that increase the energy efficiency of their operations. Customers who wish to receive a financial incentive through this program are required to submit an energy efficiency project proposal for review by the Company to determine project viability and cost-effectiveness. The Custom Efficiency Program also encourages and assists commercial and industrial Customers to use electricity in an economically efficient manner through education and information, expert audits, monitoring and verification, and industrial energy efficiency demonstration projects.

QUALIFICATIONS

Project viability will be determined through a collaborative process involving the Company, a participating Customer, and if necessary, a qualified third party or the Customer's licensed Professional Engineer. Potential projects will be evaluated for program eligibility based upon the following criteria:

1. The technology must be generally accepted cost-effective energy efficiency technology. This determination will be at the Company's sole discretion.

2. Projects must not be started or equipment ordered until after the Customer has obtained written approval from the Company.

3. Projects must be completed within 12 months of the approval date unless the Customer has obtained a written extension from the Company.

SCHEDULE 81
CUSTOM EFFICIENCY
PROGRAM
(Continued)

QUALIFICATIONS (Continued)

1. Projects must exceed the current established building code requirements or standard practice for the applicable industry as determined by the Company.

2. Projects must have the potential to save a minimum of 100,000 kilowatt-hours annually. If a project does not save a minimum of 100,000 kilowatt-hours annually and no corresponding measure is available under Schedule 80 – Easy Upgrades Program, then the project may be submitted for review by the Company and, if cost effective, the project will be eligible for a financial incentive at the same rate as the Cost-Share Option.

Incentives will not be paid for measures required by Oregon code, mandated by federal standards, or otherwise required.

INCENTIVE OPTIONS

There are two incentive options available under the Custom Efficiency program; the Cost-Share option or the Self-Directed Funds option. The Cost-Share option is available to all Customers that meet the requirements of the Custom Efficiency Program. The Self-Directed Funds option is available only to Customers taking service under Schedule 19. Upon selecting an incentive option, Customers must remain committed to their selection until January 1, 2011. The maximum incentive payment will not exceed $0.12 per annual kilowatt-hour saved under either program incentive option.

Cost-Share Option. Financial incentives are determined under the Cost-Share option using the lesser of the following two calculations:

1. $0.12 per annual kilowatt-hour saved

2. 70% of total project costs

Self-Directed Funds Option. Under the Self-Directed Funds option, the Company establishes an individual account in which the Customer's contributions to the Energy Efficiency Tariff Rider are tracked. Customers selecting this option will have direct use of 100% of the funds expected to accrue within their individual account until January 1, 2011 for implementation of cost-effective DSM projects. Any individually tracked funds not utilized for a specific project by January 1, 2011 will be removed from the individual account and pooled with the rest of the Energy Efficiency Rider, Schedule 91, funds. Selection of the Self-Directed Funds option requires Customers to continue to contribute to an individual account until January 1, 2011. Customers may combine individual account funds from multiple sites to implement cost-effective DSM projects under this option.

SCHEDULE 82
COMMERCIAL ENERGY CONSERVATION SERVICES PROGRAM

AVAILABILITY

Service under this schedule is available throughout the Company's service area within the State of Oregon to commercial building Customers who qualify for the commercial energy conservation services program.

APPLICABLE

Service under this schedule is applicable to all commercial Customers who qualify under Senate Bill 111 or OAR 860-30-040 et seq., provided the Customer meets the provisions of service set forth herein.

DEFINITIONS

Commercial Building means a public building as defined in ORS 456.746.

Commercial Building Customer means the owner or tenant of a commercial building who is responsible for paying electricity costs of the building whether they are billed under General Service Schedules 7 or 9, or schools billed under Schedule 19, or commercial portions of industrial plants billed under other schedules.

Commercial Energy Audit means the service provided to a commercial building Customer which includes on-site data gathering, energy use analysis, and a report to the Customer recommending energy conservation measures, and an estimate of the cost/benefit of those measures.

Commercial Energy Auditor or Level I Auditor means a person who is qualified through general training and experience and who has demonstrated a general knowledge of heat transfer principals, construction terms and components, energy efficient operations and maintenance procedures, boiler and furnace efficiency improvements, infiltration controls, envelope weatherization, heating, ventilating, and air conditioning (HVAC) systems, electric control systems, lighting systems, solar insolation, and applicable energy conservation measures.

Commercial Energy Specialist or Level II Auditor means a person who is qualified through specialized training and experience, such as an engineer, architect or other specialist, who has demonstrated knowledge and abilities of a qualified commercial energy auditor, and who can in addition; (a) perform calculations of energy use analysis; (b) perform calculations of energy efficiencies of HVAC, lighting, plumbing, water, steam, control, or electrical systems; and (c) can prepare technical reports of net energy savings for energy conservation measures.

Conservation Services means those services specified in Oregon Laws 1981, Chapter 708, Sections 3(1) and 15(1)-3.

Energy Conservation Measures means conservation measures which generally require greater investment than operation and maintenance practices and typically have a payback period longer than one year. These measures include, but are not limited: (a) infiltration controls, (b) heating, ventilating, and air conditioning (HVAC) system modifications, (c) heat recovery devices, (d) envelope weatherization, (e) automatic control systems, (f) solar water heaters, (g) water heating heat pumps, (h) lighting system improvement, and (i) furnace and boiler efficiency improvement.

SCHEDULE 82
COMMERCIAL ENERGY
CONSERVATION
SERVICES PROGRAM
(Continued)

DEFINITIONS (Continued)

Operation and Maintenance Practices means practices that are presumed to be cost effective if there is little or no cost associated with the item and the simple payback period is less than one year. These practices include, but are not limited to: temperature setbacks, water flow reductions, reduced use of ancillary systems, or reduced use when a building is unoccupied, repairing air duct leaks, and steam system and furnace or boiler maintenance.

COMMERCIAL ENERGY AUDIT PROGRAM

The Company shall have available, upon request, information about energy saving operations and maintenance measures for commercial buildings. The information will be tailored to special classes of commercial building Customers.

The Company will notify annually by mail each Commercial Building Customer of the availability of information and materials about energy conservation and of Commercial Energy Audit services. New Commercial Building Customers shall be given this information and offered services at the time of application for electric service.

The Company will advise each audited Commercial Building Customer of estimated energy savings, the estimated reduction of electric service billings that would be realized during the first year, and an estimate of the cost/benefit of items recommended.

SCOPE OF THE AUDIT

When the Company receives a Commercial Energy Audit request from a Commercial Building Customer who uses an average of less than 4,000 kWh of electricity per month on a yearly basis, a qualified Company Commercial Energy Auditor will perform an onsite Commercial Energy Audit to collect data and evaluate Energy Conservation Measures including, but not limited to: (a) operations and maintenance practices, (b) simple automatic control systems, (c) envelope weatherization, (d) infiltration controls, and (e) lighting system improvements.

When the Company receives a request from a Commercial Building Customer who uses an average of more than 4,000 kWh of electricity per month on a yearly basis, the Company may use a Commercial Energy Specialist to perform a Commercial Energy Audit and evaluate more complex Energy Conservation Measures such as sophisticated automatic control systems, furnace and boiler efficiency improvements, heat recovery devices, HVAC system modifications, lighting system improvements, and solar water heaters or water heating heat pumps. The Commercial Building Customer shall be furnished an estimate of the total cost of the Commercial Energy Audit and the amount of reimbursement to be received from the Company.

Company reports to a Commercial Building Customer will include as a minimum: a brief description of the building's systems which consume energy and their overall condition; an energy use analysis; recommended operations and maintenance practices; Energy Conservation Measures including a description of each measure, and its estimated costs and dollar savings for the first year. Estimated net energy savings will be calculated. Information about the availability of state and federal tax credits and low cost financing options for the Commercial Building Customer will also be included.

SCHEDULE 82
COMMERCIAL ENERGY
CONSERVATION
SERVICES PROGRAM
(Continued)

SCOPE OF THE AUDIT (Continued)

If a Commercial Building Customer qualifies for equal or better audit services under another federal, state, or local government or utility program, the Company will refer the Commercial Building Customer to that program. Utilization of such services shall be at the option of the Customer.

FEES

There will be no charge to the Commercial Building Customer for a Commercial Energy Audit performed by a Commercial Energy Auditor. If it is necessary to utilize a commercial energy specialist to evaluate more complex Energy Conservation Measures, the Company may ask the Commercial Building Customer to participate in the costs to be incurred in performing the Commercial Energy Audit. Participation by the Commercial Building Customer in the costs to be incurred shall be in accordance with a prior, written agreement between the Commercial Building Customer and the Company. The Company will contribute toward the cost of performing the Commercial Energy Audit, an amount no less than the average amount contributed toward a Commercial Energy Audit performed by a Company Commercial Energy Auditor.

COORDINATION OF UTILITIES

Where more than one energy supplier serves a building, the Company will cooperate with other suppliers in conducting a joint analysis and preparing combined recommendations for the Customers.

If the Commercial Building Customer uses oil, wood, or a renewable resource in the building, the Company shall make reasonable efforts to determine or estimate previous energy use for that energy system, and shall evaluate the operations and maintenance aspects of the system. Where the practices and systems seem to warrant attention beyond the capability of the Commercial Energy Auditor or Specialist, the Customer shall be referred to the oil or wood supplier, qualified contractor, engineer, or architect.

RULES AND REGULATIONS

Service under this schedule is subject to the Rules and Regulations contained in the Tariff of which this schedule is a part and to those prescribed by regulatory authorities.

SCHEDULE 83
BUILDING EFFICIENCY
PROGRAM

AVAILABILITY

Service under this schedule is available throughout the Company's service area within the State of Oregon to commercial building owners or developers who construct or remodel commercial buildings that will take service under the Company's Schedule 7, Schedule 9, or Schedule 19 upon completion.

APPLICABILITY

This schedule is applicable to commercial buildings scheduled to undergo new construction, expansion or major renovations. Applicable major renovations must include professional design services, substantial replacement of major building components, and be subject to review by code authorities.

PROGRAM DESCRIPTION

Building Efficiency is an incentive-based program designed to help cover a portion of the costs of designing and building energy efficiency features into commercial construction projects. Building Efficiency uses a prescriptive approach to provide incentives for specific lighting and cooling efficiency options.

INCENTIVE STRUCTURE

To be eligible for an incentive, installation of the qualifying equipment cannot have started prior to January 1, 2006. Incentives will not be paid for measures required by Oregon code, mandated by federal standards, or otherwise required. Incentive payments will not exceed 100% of the installed cost for any specified measure. Eligible projects are subject to a maximum incentive cap of $100,000 per project.

Applicable Measures		
Measure Type	Incentive	Eligibility Requirements
Premium performance windows	$1 per square foot	Premium performance windows must be certified according to the test procedures established by the National Fenestration Rating Council (NFRC) and meet the Commercial Window Initiative (CWI) minimum specifications.
High performance windows	$0.50 per square foot	High performance windows must be certified according to the test procedures established by the National Fenestration Rating Council (NFRC) and must have a U-Factor rating of 0.42 or below and a Solar Heat Gain Coefficient of 0.40 or below.
Reflective roof treatment	$0.05 per square foot of roof treatment	Reflective roof treatments must meet total initial solar reflectivity of 0.70 and an emissivity of 0.75 consistent with California's Title 24 standards for flat or minimally pitched roofs.

SCHEDULE 83
BUILDING EFFICIENCY
PROGRAM
(Continued)

INCENTIVE STRUCTURE (Continued)

Applicable Measures (Continued)		
Measure Type	Incentive	Eligibility Requirements
Air side economizer	$75 per ton of air conditioning economized	Applicable economizers must allow outdoor air capacity to meet at least 85% of an air conditioning unit's airflow rate coupled with a programmable thermostat capable of two-stage cooling controls. Limited to applications where economizers are not already required by code.
Premium efficiency air conditioning and heat pump systems	$75 per ton of air conditioning	Systems with single-phase units of 5 tons of cooling capacity or less must meet Consortium for Energy Efficiency (CEE) minimum specifications as set forth in Tier II of the High-Efficiency Commercial Air Conditioning and Heat Pumps Initiative (HECAC). All other systems must meet the CEE minimum specifications set forth in Tier I of the HECAC initiative.
Additional air conditioning unit efficiency bonus	$2.50 per ton of air conditioning for each 1/10 unit of (S)EER above the standard	Air conditioning units that exceed the HECAC Tier II standard are eligible for an additional incentive paid on the basis of the unit's cooling capacity (in tons) multiplied by each 1/10 of a point that the Seasonal Energy Efficiency Ratio (SEER) or Energy Efficiency Rating (EER) exceeds the HECAC Tier II specified minimum.
High performance complex cooling system	$250 per ton of air conditioning for each unit of COP above the standard	Complex systems without SEER or EER ratings are eligible for an incentive paid on the basis of the unit's cooling capacity (in tons) multiplied by the amount that the Coefficient of Performance (COP) exceeds the minimums specified in Table 13-O of the 2004 Oregon Structural Specialty Code.
Variable speed drives	$60 per horsepower	Variable speed controls for fans, pumps and other variably-loaded electric motors between 5 and 100 horsepower operating a minimum of 2,000 hours annually are eligible for an incentive when installed in accordance with Institute of Electrical and Electronics Engineers (IEEE) Standard 519.
Energy management control system	$0.30 per square foot of controlled space	Systems must provide automatic control of lighting, heating, cooling or other energy using systems and operate under a control schedule that results in energy savings over standard operation subject to verification by the Company.
Demand Controlled Ventilation (DCV)	$0.50 per CFM of HVAC unit airflow	DCV systems must automatically adjust ventilation rates based on occupancy levels using carbon dioxide sensors. HVAC systems must include outside ventilation capacities of at least 1,500 cubic feet per minute (CFM) and serve areas with variable occupant loading.
Reduced power density lighting system	$0.05 per square foot covered by the lighting	Lighting systems designed with a lighting power density (LPD) that is at least 10 % below the 2004 Oregon Structural Specialty Code as detailed in Table 13-G will be eligible for this incentive.

SCHEDULE 83
BUILDING EFFICIENCY
PROGRAM
(Continued)

INCENTIVE STRUCTURE (Continued)

Applicable Measures (Continued)		
Measure Type	Incentive	Eligibility Requirements
Daylighting photo controls	$0.25 per square foot of daylit space	Daylighting photo controls dim or turn off electric lights in response to levels of natural daylight. To qualify for an incentive, the design must include a consultation with the Integrated Design Lab or other qualified daylighting professional.
Occupancy sensor controls	$25 per sensor installed	Occupancy sensors are automatic switching devices that sense human occupancy and control the lighting system accordingly. Either wall- or ceiling-mounted sensors are eligible where not already required by code.
High efficiency exit signs	$7.50 per installed sign	Any code compliant exit sign that draws less than 4 watts per sign face including, but not limited to, light emitting diode (LED), cold cathode, electroluminescent, or self-luminous exit signs are eligible for an incentive.

SCHEDULE 84
CUSTOMER ENERGY
PRODUCTION NET METERING

In compliance with ORS 757.300, the Company offers net metering services to its customers in Oregon in accordance with tariffs, schedules and other regulations which are in effect in its Idaho service territory. For its Idaho service territory, the Company's Schedule 84 sets forth the provisions which govern its net metering service offering. Idaho Schedule 84 is available on the Company's Web site at www.idahopower.com.

SCHEDULE 85
COGENERATION AND SMALL POWER PRODUCTION STANDARD CONTRACT RATES

AVAILABILITY

Service under this schedule is available for power delivered to the Company's control area within the State of Oregon.

APPLICABILITY

Service under this schedule is applicable to any Seller that:

1) Owns or operates a Qualifying Facility with a Nameplate Capacity rating of 10 MW or less and desires to sell Energy generated by the Qualifying Facility to the Company in compliance with all the terms and conditions of the Standard Contract;

2) Meets all applicable requirements of the Company's Generation Interconnection Process.

For Qualifying Facilities with a Nameplate Capacity rating greater than 10 MW, a negotiated Non-Standard Contract between the Seller and the Company is required.

DEFINITIONS

Energy means the electric energy, expressed in kWh, generated by the Qualifying Facility and delivered by the Seller to the Company in accordance with the conditions of this schedule and the Standard Contract. Energy is measured net of Losses and Station Use.

Generation Interconnection Process is the Company's generation interconnection application and engineering review process developed to ensure a safe and reliable generation interconnection in compliance with all applicable regulatory requirements, Prudent Electrical Practices and national safety standards. The Generation Interconnection Process is managed by the Company's Delivery Business Unit.

Heat Rate Conversion Factor is 7,100 MMBTU divided by 1,000.

Intermittent describes a Qualifying Facility that produces electrical energy from the use of wind, solar or run of river hydro as the prime mover.

Losses are the loss of electric energy occurring as a result of the transformation and transmission of electric energy from the Qualifying Facility to the Point of Delivery.

Nameplate Capacity means the full-load electrical quantities assigned by the designer to a generator and its prime mover or other piece of electrical equipment, such as transformers and circuit breakers, under standardized conditions, expressed in amperes, kilovolt amperes, kilowatts, volts, or other appropriate units. Usually indicated on a nameplate attached to the individual machine or device.

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

DEFINITIONS (Continued)

Non-Standard Contract is a negotiated contract between any Seller that owns or operates a Qualifying Facility with a nameplate capacity rating greater than 10 MW and desires to sell Energy generated by the Qualifying Facility to the Company. The starting point for negotiation of price is the Avoided Cost Components established in this schedule and may be modified to address specific factors mandated by federal and state law, including

1) The utility's system cost data;

2) The availability of capacity or energy from a Qualifying Facility during the system daily and seasonal peak periods, including:

a. The ability of the utility to dispatch the qualifying facility;

b. The expected or demonstrated reliability of the qualifying facility;

c. The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;

d. The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;

e. The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

f. The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and

g. The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and

3) The relationship of the availability of energy or capacity from the Qualifying Facility to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a Qualifying Facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

DEFINITIONS (Continued)

Non-Standard Contract is a negotiated contract between any Seller that owns or operates a Qualifying Facility with a Nameplate Capacity rating greater than 10 MW and desires to sell Energy generated by the Qualifying Facility to the Company. The guidelines for negotiating a Non-Standard Contract are more specifically described later in this schedule in Guidelines for Negotiation of Power Purchases Agreements for Qualifying Facilities with Nameplate Capacity of 10 MW or Larger.

Point of Delivery is the location where the Company's and the Seller's electrical facilities are inter-connected or where the Company's and the Seller's host transmission provider's electrical facilities are interconnected.

Prudent Electrical Practices are those practices, methods and equipment that are commonly used in prudent electrical engineering and operations to operate electric equipment lawfully and with safety, dependability, efficiency and economy.

PURPA means the Public Utility Regulatory Policies Act of 1978.

Qualifying Facility or QF is a cogeneration facility or a small power production facility which meets the PURPA criteria for qualification set forth in Subpart B of Part 292, Subchapter K, Chapter I, Title 18, of the Code of Federal Regulations.

Seasonality Factor is the factor used in determining the seasonal purchase price of energy. The applicable factors are:

73.50% for Season 1 (March, April, May);
120.00% for Season 2 (July, August, November, December);
100.00% for Season 3 (June, September, October, January, February).

Seller is any entity that owns or operates a Qualifying Facility and desires to sell Energy to the Company.

Standard Contracts are the pro forma Energy Sales Agreements the Company maintains on file with the Public Utility Commission of Oregon for Intermittent and non-intermittent on-system Qualifying Facilities and Intermittent and non-intermittent off-system Qualifying Facilities, with a Nameplate Capacity of 10 MW or less.

Station Use is electric energy used to operate the Qualifying Facility which is auxiliary to or directly related to the generation of electricity and which, but for the generation of electricity, would not be consumed by the Seller.

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

QUALIFYING FACILITY INFORMATION INQUIRY PROCESS

There are two separate processes required for a Seller to deliver and sell energy from a Qualifying Facility to the Company. These processes may be completed separately or simultaneously.

1) Generation Interconnection Process

All generation projects physically interconnecting to the Company's electrical system, regardless of size, location or ownership, must successfully complete the Generation Interconnection Process prior to the project delivering energy to the Company. A complete description of the Small Generator Interconnection Procedures, the Interconnection Application and Company contact information is maintained on the Idaho Power website at www.idahopower.com, or Seller may contact the Company's Delivery Business Unit at 1-208-388-2658 for further information.

All generation projects delivering power under the off-system Energy Sales Agreement must successfully complete a comparable Generation Interconnection Process with the Seller's host interconnection provider and transmission provider.

2) Energy Sales Agreement

To begin the process of completing a Standard Contract or negotiating a Non-Standard Contract, for a proposed project, the Seller must submit to the Company a request for an Energy Sales Agreement. All requests will be processed in the order of receipt by the Company.

A. Communications

Unless otherwise directed by the Company, all communications to the Company regarding an Energy Sales Agreement should be directed in writing as follows:

Idaho Power Company
Cogeneration and Small Power Production
P O Box 70
Boise, Idaho 83707

B. Procedures

1. The Company's approved Energy Sales Agreement may be obtained from the Company's website at http://www.idahopower.com or if the Seller is unable to obtain it from the website, the Company will send a copy within 10 business days of a written request.

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

QUALIFYING FACILITY INFORMATION INQUIRY PROCESS (Continued)

1. In order to obtain a project specific draft Energy Sales Agreement the Seller must provide in writing to the Company, general project information required for the completion of an Energy Sales Agreement, including, but not limited to:

a) Date of request
b) Company / Organization that will be the contracting party
c) Contract notification information including name, address and telephone number
d) Verification that the Qualifying Facility meets the "Eligibility for Standard Rates and Contract" criteria
e) Copy of the Qualifying Facility's QF certificate
f) Copy of the FERC license (applicable to hydro projects only)
g) Location of the proposed project including general area and specific legal property description
h) Description of the proposed project including specific equipment models, types, sizes and configurations
i) Type of project (wind, hydro, geothermal etc)
j) Nameplate capacity of the proposed project
k) Schedule 85 pricing option selected
l) Desired term of the Energy Sales Agreement
m) Annual net energy amount
n) Maximum capacity of the Qualifying Facility
o) Estimated first energy date
p) Estimated operation date
q) Point of Delivery
r) Status of the Generation Interconnection Process

3. The Company shall provide a draft Energy Sales Agreement when all information described in Paragraph 2 above has been received in writing from the Seller. Within 15 business days following receipt of all information required in Paragraph 2, the Company will provide the Seller with a draft Energy Sales Agreement including current standard avoided cost prices and/or other optional pricing mechanisms as approved by the Oregon Public Utility Commission in this Schedule.

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

QUALIFYING FACILITY INFORMATION INQUIRY PROCESS (Continued)

4. The Company will respond within 15 business days to any written comments and proposals that the Seller provides in response to the draft Energy Sales Agreement.

5. If the Seller desires to proceed with the Energy Sales Agreement after reviewing the Company's draft Energy Sales Agreement, it may request in writing that the Company prepare a final draft Energy Sales Agreement. In connection with such request, the Seller must provide the Company with an updated status of the Generation Interconnection Process which indicates that the Seller's provided information (i.e. first energy date, operation date, etc.) are realistically attainable and any additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft Energy Sales Agreement. Once the Company has received the written request for a final draft Energy Sales Agreement and all additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft Energy Sales Agreement, the Company will provide Seller with a final draft Energy Sales Agreement within 15 business days.

6. After reviewing the final draft Energy Sales Agreement, the Seller may either prepare another set of written comments and proposals or approve the final draft Energy Sales Agreement. If the Seller prepares written comments and proposals, the Company will respond within 15 business days to those comments and proposals.

7. When both parties are in full agreement as to all terms and conditions of the final draft Energy Sales Agreement, the Company will prepare and forward to the Seller within 15 business days a final executable version of the Energy Sales Agreement. Once the Seller executes the Energy Sales Agreement and returns all copies to the Company, the Company will execute the Energy Sales Agreement. Following the Company's execution a completely executed copy will be returned to the Seller. Prices and other terms and conditions in the Energy Sales Agreement will not be final and binding until the Energy Sales Agreement has been executed by both parties.

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

AVOIDED COST COMPONENTS

The Avoided Cost Components are calculated based upon the Surrogate Avoided Resource methodology (SAR) for determining the Company's standard avoided costs.

Year	Capacity Cost (mills/kWh)	Fuel Cost (mills/kWh)
2007	25.00	60.60
2008	25.61	56.24
2009	26.22	55.61
2010	26.86	41.48
2011	27.50	41.83
2012	28.17	42.46
2013	28.85	43.87
2014	29.55	45.13
2015	30.26	46.68
2016	31.00	48.65
2017	31.75	50.83
2018	32.52	52.65
2019	33.31	55.26
2020	34.12	57.36
2021	34.95	52.80
2022	35.80	54.76
2023	36.67	57.22
2024	37.57	58.91
2025	38.48	61.16
2026	39.42	56.87
2027	40.39	59.33
2028	41.37	61.51
2029	42.39	63.83
2030	43.43	66.64
2031	44.49	67.56
2032	45.58	68.47
2033	46.70	69.46
2034	47.85	70.37
2035	49.02	71.28
2036	50.23	72.20

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

NET ENERGY PURCHASE PRICE

The Company will pay the Seller monthly, for each kWh of Energy delivered and accepted at the Point of Delivery during the preceding calendar month, in accordance with the Standard Contract, an amount determined by the Seller's choice of one of the following options:

Option 1 - Fixed Price Method

Net Energy Purchase Price =

On-peak = (Fuel Cost + Capacity Cost) X Seasonality Factor
Off-peak = Fuel Cost X Seasonality Factor

where

Fuel Cost and Capacity Cost are the Avoided Cost Components established in this schedule for the applicable calendar year of the actual Net Energy deliveries to the Company.

Option 2 – Dead Band Method

Net Energy Purchase Price =

On-peak = (AGPU + Capacity Cost) X Seasonality Factor
Off-peak = AGPU X Seasonality Factor

Actual Gas Price Used (AGPU) =
90% of Fuel Cost if
Indexed Fuel Cost is less than 90% Fuel Cost; else
110% of Fuel Cost if
Indexed Fuel Cost is greater than 110% Fuel Cost; else
Indexed Fuel Cost

where

Fuel Cost and Capacity Cost are the Avoided Cost Components established in this schedule for the applicable calendar year of the actual Net Energy deliveries to the Company, and

Indexed Fuel Cost is the applicable weighted monthly average index price of natural gas at Sumas multiplied by the Heat Rate Conversion Factor.

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

NET ENERGY PURCHASE PRICE (Continued)

Option 3 – Gas Market Method

Net Energy Purchase Price =

On-peak = (AGPU + Capacity Cost) X Seasonality Factor
Off-peak = AGPU X Seasonality Factor

Actual Gas Price Used (AGPU) = Indexed Fuel Cost

where

Capacity Cost is the Avoided Cost Component established in this schedule for the applicable calendar year of the actual Net Energy deliveries to the Company, and

Indexed Fuel Cost is the applicable weighted monthly average index price of natural gas at Sumas multiplied by the Heat Rate Conversion Factor.

MISCELLANEOUS PROVISIONS

Insurance

Qualifying Facilities with a Nameplate Capacity of 200 kilowatts or smaller are not required to provide evidence of liability insurance.

GUIDELINES FOR NEGOTIATION OF POWER PURCHASE AGREEMENTS FOR QFS WITH A NAMEPLATE CAPACITY OF 10 MW OR LARGER

1) The Company will not impose terms and conditions beyond what is standard practice. The Edison Electric Institute master agreement and the Company's Standard Contracts are useful starting points in negotiating QF agreements.

2) The Company will provide an indicative pricing proposal for a QF that plans to provide firm energy or capacity and chooses avoided cost rates calculated at the time of the obligation. The Company will provide an indicative pricing proposal within 30 days of receipt of the information the Company requires from the QF. The proposal may include other terms and conditions, tailored to the individual characteristics of the proposed project. The avoided cost rates in the indicative pricing proposal will be based on the following:

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

GUIDELINES FOR NEGOTIATION OF POWER PURCHASE AGREEMENTS FOR QFS WITH A NAMEPLATE CAPACITY OF 10 MW OR LARGER (Continued)

a. The starting point for negotiations is the avoided cost calculated under the modeling methodology approved by the Idaho Public Utilities Commission for QFs over 10 MW, as refined by the Oregon Public Utility Commission to incorporate stochastic analyses of electric and natural gas prices, loads, hydro and unplanned outages.

b. The prospective QF may request in writing that the Company prepare a draft power purchase agreement to serve as the basis for negotiations. The Company may require additional information from the QF necessary to prepare a draft agreement.

c. Within 30 days of receiving the required information, the Company will provide a draft power purchase agreement containing a comprehensive set of proposed terms and conditions.

d. The QF must submit in writing a statement of its intention to begin negotiations with the Company and may include written comments and proposals. The Company is not obligated to begin negotiations until it receives written notification from the QF. The Company will not unreasonably delay negotiations and will respond in good faith to all proposals by the QF.

e. When the parties have agreed, the Company will prepare a final version of the contract within 15 business days. A contract is not final and binding until signed by both parties.

f. At any time after 60 days from the date the QF has provided its written notification pursuant to paragraph d., the QF may file a complaint with the Oregon Public Utility Commission asking the Commission to adjudicate any unresolved contract terms and conditions.

2) QFs have the unilateral right to select a contract length of up to 20 years for a PURPA contract. The contract length selected by the QF may impact other contractual issues including, but not limited to, the avoided cost determination with respect to that QF.

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

GUIDELINES FOR NEGOTIATION OF POWER PURCHASE AGREEMENTS
FOR QFS WITH A NAMEPLATE CAPACITY OF 10 MW OR LARGER (Continued)

1) The Company should consider the QF to be providing firm energy or capacity if the contract requires delivery of a specified amount of energy or capacity over a specified term and includes sanctions for non-compliance under a legally enforceable obligation. The Company shall not determine that a QF provides no capacity value simply because the Company did not select it through a competitive bidding process. For a QF providing firm energy or capacity:

a. The Company and the QF should negotiate the time periods when the QF may schedule outages and the advance notification requirement for such outages, using provisions in the Company's partial requirements tariffs as guidance.

b. The QF should be required to make best efforts to meet its capacity obligations during Company system emergencies.

c. The Company and the QF should negotiate security, default, damage and termination provisions that keep the Company and its ratepayers whole in the event the QF fails to meet obligations under the contract.

d. Delay of commercial operation should not be a cause of termination if the Company determines at the time of contract execution that it will be resource-sufficient as of the QF on-line date specified in the contract; however, damages may be appropriate.

e. Lack of natural motive force for testing to prove commercial operation should not be a cause of termination.

f. The Company should include a provision in the contract that states the Company may require a QF terminated due to its default and wishing to resume selling to the Company be subject to the terms of the original contract until its end date.

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

GUIDELINES FOR NEGOTIATION OF POWER PURCHASE AGREEMENTS
FOR QFS WITH A NAMEPLATE CAPACITY OF 10 MW OR LARGER (Continued)

1) An "as available" obligation for delivery of energy, including deliveries in excess of Nameplate Capacity or the amount committed in the QF contract, should be treated as a non-firm commitment. Non-firm commitments should not be subject to minimum delivery requirements, default damages for construction delay or under-delivery, default damages for the QF choosing to terminate the contract early, or default security for these purposes.

2) For QFs unable to establish creditworthiness, the Company must at a minimum allow the QF to choose either a letter of credit or cash escrow for providing default security. When determining security requirements, the Company should take into account the risk associated with the QF based on such factors as its size and type of supply commitments.

3) When QF rates are based on avoided costs calculated at the time of delivery, the Company should use day-ahead on- and off-peak market index prices at the appropriate market hub(s).

a. For QFs providing firm energy or capacity that choose this option, avoided cost rates should be based on day-ahead market index prices for firm purchases.

b. For QFs providing energy on an "as available" basis, avoided cost rates should be based on day-ahead market index prices for non-firm purchases.

4) The Company should not make adjustments to standard avoided cost rates other than those approved by the Oregon Public Utility Commission and consistent with these guidelines.

5) The Company should make adjustments to avoided costs for reliability on an expected forward-looking basis. The Company should design QF rates to provide an incentive for the QF to achieve the contracted level and timing of energy deliveries.

6) The Company should make adjustments to avoided costs for dispatchability on a probabilistic, forward-looking basis.

7) If avoided cost rates for a QF are calculated at the time of the obligation and the Company's avoided resource is a fossil fuel plant, the Company should adjust avoided cost rates for the resource deficiency period to take into account avoided fossil fuel price risk.

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

GUIDELINES FOR NEGOTIATION OF POWER PURCHASE AGREEMENTS
FOR QFS WITH A NAMEPLATE CAPACITY OF 10 MW OR LARGER (Continued)

1) Avoided cost rates for wind QFs should be adjusted for integration cost estimates based on studies conducted for the Company's system, unless the QF contracts for integration services with a third party.

a. The Company should use the most recent integration cost data available, consistent with its evaluation of competitively bid and self-build wind resources.

b. The portion of integration costs attributable to reserves costs should be based on the difference in such costs between the wind QF and the Company proxy plant.

c. The Company should base first-year integration costs on the actual level of wind resources in the control area, plus the proposed QF. Integration costs for years two through five of the contract should be based on the expected level of wind resources in the control area each year, including the new resources the Company expects to add. Integration costs should be fixed at the year-five level, adjusted for inflation, for the remainder of the life of the wind projects in the control area.

d. The Company is prohibited from using a long-range planning target for wind resources as the basis for integration costs. However, if the Company is subject to near-term targets under a mandatory Renewable Portfolio Standard, the Company may base its integration costs on the level of renewable resources it must acquire over the next 10 years.

e. In determining integration costs, the Company should make reasonable estimates regarding the portion of renewable resources to be acquired that will be intermittent resources.

2) The Company should adjust avoided cost rates for QF line losses relative to the Company proxy plant based on a proximity-based approach.

3) The Company should evaluate whether there are potential savings due to transmission and distribution system upgrades that can be avoided or deferred as a result of the QFs location relative to the Company proxy plant and adjust avoided cost rates accordingly.

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

GUIDELINES FOR NEGOTIATION OF POWER PURCHASE AGREEMENTS FOR QFS WITH A NAMEPLATE CAPACITY OF 10 MW OR LARGER (Continued)

1) The Company should not adjust avoided cost rates for any distribution or transmission system upgrades needed to accept QF power. Such costs should be separately charged as part of the interconnection process.

2) The Company should not adjust avoided cost rates based on its determination of the additional cost it might incur for any debt imputation by a credit rating agency.

3) Regarding Surplus Sale and Simultaneous Purchase and Sale:

a. QFs may either contract with the Company for a "surplus sale" or for a "simultaneous purchase and sale" provided, however, that the QFs selection of either such contractual arrangement shall not be inconsistent with any retail tariff provision of the Company then in effect or any agreement between the QF and the Company;

b. The two sale/purchase arrangements described in paragraph 17. a will be available to QFs regardless of whether they qualify for standard contracts and rates or non-standard contracts and rates, however the "simultaneous purchase and sale" is not available to QFs not directly connected to the Company's electrical system;

c. The negotiation parameters and guidelines should be the same for both sale/purchase arrangements described in paragraph 17. a; and

d. The avoided cost calculations by the Company do not require adjustment solely as a result of the selection of one of the sale/purchase arrangements described in paragraph 17. a, rather than the other.

SCHEDULE 87
MANUFACTURED HOUSING
ENERGY EFFICIENCY PROGRAMS

This schedule describes the manufactured housing energy efficiency programs offered by the Company and funded by the Energy Efficiency Rider.

REBATE ADVANTAGE MANUFACTURED HOME INCENTIVES PROGRAM

AVAILABILITY

This program is available to a Customer who signs a sales agreement for a new ENERGY STAR® all-electric manufactured home. Sales of used homes or indirect sales of new homes are not eligible for this program. Applications to participate in the program are available through local manufactured home dealers. Incentives will be available on a first-come, first-served basis.

APPLICABILITY

This program is applicable to homes manufactured by an ENERGY STAR® homes manufacturer. In order to participate in the program, the home must be served under a residential electric service schedule and be sited in the Company's Oregon service territory.

SERVICE PROVIDED

Incentives are provided by the Company to Customers who purchase an eligible new all-electric manufactured home and to the sales consultant who sells the home in the following amounts:

Home Type	Customer Incentive	Sales Bonus
ENERGY STAR® qualified	$500 per eligible home	$100 per home

ENERGY HOUSE CALLS FOR MANUFACTURED HOMES PROGRAM

AVAILABILITY

This program is available to a Customer who lives in a manufactured or mobile home that is heated with an electric furnace or heat pump. The program will be effective through December 31, 2009.

APPLICABILITY

This program is applicable to Customers who own or rent a manufactured or mobile home. Renters must receive prior written approval from landlords to participate in the program. The Company shall have the sole right to determine whether the service is cost-effective. The Company also retains the right to not authorize service at homes deemed to be structurally unsound or posing other hazardous conditions.

SCHEDULE 87
MANUFACTURED HOUSING
ENERGY EFFICIENCY PROGRAMS
(Continued)

ENERGY HOUSE CALLS FOR MANUFACTURED HOMES PROGRAM (Continued)

SERVICE PROVIDED

The Customer may schedule a free Energy House Call by either contacting a Company-approved certified contractor, or positively responding to an offer from a certified contractor. The certified contractor will test the duct system for leaks. If a leak exists, the contractor will seal the leak at no charge according to regional standards outlined by the Bonneville Power Administration (BPA). In addition, program participants will receive the following free services: five compact fluorescent light bulbs, two air filters, a water heater temperature check and education information about energy efficiency.

SCHEDULE 89
SAVINGS WITH A TWIST
PROGRAM (SWAT)

This schedule describes the "Saving With A Twist Program" offered by the Company and sponsored by the Bonneville Power Administration (BPA) and coordinated by the Northwest ENERGY STAR® Con sumer Products Program.

AVAILABILITY

This program is available to customers purchasing designated compact fluorescent light (CFL) bulbs from participating retailers. Bulbs can be purchased as available on a first-come, first-served basis. The program will be effective from September 1, 2006 through December 15, 2006 or until the bulbs for the Program are exhausted, whichever is earlier.

SERVICE PROVIDED

Designated CFL bulbs range from 18-26 watts. Using BPA Conservation Rate Credit funds, the Company will pay Portland Energy Conservation, Inc. (PECI) for manufacturers' buy-down fees plus their program administration costs. The bulbs will be distributed to participating retailers to be sold for a price of $0.99-$1.29 per bulb. PECI will develop marketing and in-store point-of-purchase education materials. The Company will include its logo on selected marketing materials. PECI will also maintain a tracking database for Program managers.

SCHEDULE 90
DIRECT ACCESS PILOT PROGRAM
ENERGY SERVICE

DISCONTINUE

AVAILABILITY

Service under this schedule is available in all territory in the State of Oregon outside the Company's allocated Oregon service territory where direct access pilot programs are in effect.

APPLICABILITY

Service under this schedule applies to customers who have viable alternatives to incumbent utility service under direct access pilot programs to purchase energy services from an electric energy service supplier for delivery to the system of the customer's electric delivery provider.

SPECIAL TERMS AND CONDITIONS

This tariff shall incorporate by reference any codes of conduct or terms and conditions approved by the Commission relating to electric energy service supplier participation in direct access pilot programs including, but not limited to, all cost reporting and accounting requirements for public utility electric energy service suppliers.

PRICES

Pricing under this tariff shall be market-based. The Company shall price in a manner that will not violate state or federal antitrust laws.

The Company shall price its services:

a. to cover at least the relevant costs during the term of service, and

b. to assure that just and reasonable rates are established for the Company's Customers in its allocated Oregon service territory.

SCHEDULE 91
ENERGY EFFICIENCY RIDER

APPLICABILITY

This schedule is applicable to all retail Customers served under the Company's schedules and special contracts. This Energy Efficiency Rider is designed to fund the Company's expenditures for the analysis and implementation of energy conservation and demand response programs.

MONTHLY CHARGE

The Monthly Charge is equal to the applicable Energy Efficiency Rider percentage times the sum of the monthly billed charges for the base rate components. The Monthly Charge will be separately stated on the Customer's regular billing.

Schedule	Energy Efficiency Rider
Schedule 1	1.5 %, but not to exceed $1.75 per meter per month
Schedule 7	1.5 %
Schedule 9	1.5 %
Schedule 15	1.5 %
Schedule 19	1.5 %
Schedule 24	1.5 %, but not to exceed $50.00 per meter per month
Schedule 40	1.5 %
Schedule 41	1.5 %
Schedule 42	1.5 %

SCHEDULE 92
DEPRECIATION ADJUSTMENT RIDER

PURPOSE

To recover from Customers the accelerated depreciation of the existing metering infrastructure that will be replaced by the installation of Advanced Metering Infrastructure (AMI) less the revenue requirement impact of the revised depreciation rates.

APPLICABILITY

This Schedule is applicable to all electric energy delivered to Customers served under Schedules 1, 7, 9 Secondary, and 24 Secondary.

ADJUSTMENT RATE

The Adjustment Rates, applicable for service on and after January 1, 2009, will be:

Schedule	Description	Adjustment Rate
1	Residential Service	0.0979¢ per kWh
7	Small General Service	0.0979¢ per kWh
9 Secondary	Large Power Service	0.0979¢ per kWh
24 Secondary	Irrigation Service	0.0979¢ per kWh

SPECIAL CONDITIONS

1. This Schedule will terminate within six months or less of the effective date if the Company does not commence mass deployment of meters by June 30, 2009.

2. This Schedule may be temporarily suspended in order to resolve specific issues identified during the mass deployment of meters. The Company must file an application to suspend at least 45 days before the termination deadline specified in Special Condition 1.

EXPIRATION

The Depreciation Adjustment Rider included on this Schedule will expire June 30, 2010.

SCHEDULE 95
ADJUSTMENT FOR MUNICIPAL EXACTIONS

PURPOSE

The purpose of this schedule is to set forth the exactions such as license, privilege, franchise, business, occupation, operating, excise, sales or use of street taxes or other exactions imposed on the Company by municipal corporations and billed separately by the Company to its Customers within the corporate limits of a municipality.

APPLICABILITY

This schedule is applicable to all bills for Electric Service calculated under the Company's schedules and Special Contracts in the Company's service area within the State of Oregon as provided in Rule C of this Tariff.

ADJUSTMENT

The rates and charges for Electric Service provided under the Company's schedules will be proportionately increased by the following adjustments within the municipality on and after the effective date of the applicable municipal ordinance:

Municipality	Effective Date Of Ordinance	Adjustment Over 3.5%
City of Ontario	October 1, 1995	1.5% Franchise Tax
City of Huntington	May 29, 2003	1.0% Franchise Tax

SCHEDULE 98
RESIDENTIAL AND SMALL FARM
ENERGY CREDIT

APPLICABILITY

This schedule is applicable to the qualifying electric energy delivered to residential Customers taking service under Schedule 1, qualifying long-term care facilities taking service under Schedule 7 or Schedule 9 who are not providing full medical care to residents and where the average patient stay is 30 days or longer, and to agricultural Customers operating a water pumping or water delivery system used to irrigate agricultural crops or livestock pasturage under Schedule 24.

The Residential and Small Farm Energy Credit ("Credit") is the result of the Settlement Agreement between the Company and BPA dated October 31, 2000. The Settlement Agreement provides for the determination of benefits during the period October 1, 2001 through September 30, 2011. The Credit under this schedule is effective October 26, 2001. This schedule shall expire when the benefits derived from the Settlement Agreement for the period October 1, 2001 through September 30, 2011 have been credited to customers as provided for under this schedule.

QUALIFYING ELECTRIC ENERGY

All kWh of energy delivered during the Billing Period to residential Customers taking service under Schedule 1 and qualifying long-term care facilities taking service under Schedule 7 or Schedule 9, as described above, qualifies for the Credit under this schedule. The kWh of energy delivered during the Billing Period to applicable agricultural Customers taking service under Schedule 24 which qualifies for the Credit under this schedule is limited to either the agricultural Customer's actual metered energy or 222,000 kWh, whichever is less. Agricultural Customers will be identified by tax identification number or Social Security Number for purposes of determining qualifying electric energy under this schedule.

CREDIT ADJUSTMENT

An energy credit factor for residential Customers and qualifying long-term care facilities will be computed every twelve months. The energy credit factor is determined by dividing the sum of monthly benefit derived from the Settlement Agreement for each month of the twelve-month rate period by the sum of the projected monthly kWh of energy consumption by residential Customers and qualifying long-term care facilities. The current computation of the energy credit factor is $0.000000/kWh. A Credit equal to the current factor times the qualifying kWh of electric energy for the Billing Period will be included on each Customer billing.

An energy credit factor for applicable agricultural Customers will be computed on an annual basis by dividing the annual benefit derived from the Settlement Agreement by the qualifying kWh of electric energy billed to applicable agricultural Customers for the October through September Billing Periods. A Credit equal to the credit adjustment factor times the qualifying kWh of electric energy billed to each applicable agricultural Customer during the October through September Billing Periods will be issued to each applicable agricultural Customer in December of each year.

Idaho Power/1214
Witness: Michael J. Youngblood

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Michael J. Youngblood
Proposed Tariff Sheets – Final Form

July 31, 2009

OREGON PUBLIC UTILITY COMMISSION

TARIFF NO. E-27

GENERAL RULES, REGULATIONS AND RATES

APPLICABLE TO ELECTRIC SERVICE IN THE TERRITORY

SERVED FROM THE COMPANY'S INTERCONNECTED SYSTEM

IN OREGON

GENERAL RULES AND REGULATIONS INDEX

SCHEDULE INDEX

RULE A
INTRODUCTION

These Rules and Regulations are a part of the Tariff of Idaho Power Company and apply to the Company and every Customer to whom service is supplied; provided, that in case of conflict between these Rules and Regulations and the provisions of any schedule of this Tariff, the provisions of such schedule will govern as to service supplied thereunder.

RULE B
DEFINITIONS

The terms listed below, which are used frequently in this Tariff, will have the stated meanings:

Billing Period is the period intervening between meter readings and shall be approximately 30 days. However, Electric Service covering 27-36 days inclusive will be considered a normal Billing Period.

Commission refers to the Oregon Public Utility Commission.

Company refers to Idaho Power Company.

Customer is the individual, partnership, association, organization, public or private corporation, government or governmental agency receiving or contracting for Electric Service. Customer status may be retained when a Customer voluntarily disconnects and subsequently requests service from the Company within 20 days as provided by OAR 860-021-0008.

Demand is the average kilowatts (kW) or horsepower (HP) supplied to the Customer during the 15-consecutive-minute period of maximum use during the Billing Period, as shown by the Company's meter, or determined in accordance with the demand clause in the schedule under which service is supplied. In no event, however, will the maximum demand for the Billing Period be less than the demand determined as specified in the schedule.

Electric Service is the availability of power and energy in the form and at the voltage specified in the Oregon Electric Service Application or agreement, irrespective of whether electric energy is actually utilized, measured in kilowatt-hours (kWh).

Month (unless calendar month is stated) is the approximate 30-day period coinciding with the Billing Period.

Normal Business Hours are 8:00 a.m. to 5:00 p.m., Monday through Friday, excluding holidays observed by the Company. Notices of office closures for holidays are posted, in advance, at the Company office entrances.

Point of Delivery is the junction point between the facilities owned by the Company and the facilities owned by the Customer; OR the Point at which the Company's lines first become adjacent to the Customer's property; OR as otherwise specified in the Company's Tariff.

Power Factor is the percentage obtained by dividing the maximum demand recorded in kW by the corresponding kilovolt-ampere (kVA) demand established by the Customer.

Premises is a building, structure, dwelling or residence of the Customer. If the Customer uses several buildings or structures in the operation of a single integrated commercial, industrial, or institutional enterprise, the Company may consider all such buildings or structures that are in proximity to each other to be the Premises, even though intervening ownerships or public thoroughfares exist.

RULE B
DEFINITIONS
(Continued)

Service Level is defined as follows:

Secondary Service is service taken at 480 volts or less, or when the definitions of Primary Service and Transmission Service do not apply. The Company is responsible for providing the transformation of power to the voltage at which it is to be used by the Customer taking Secondary Service.

Primary Service is service taken at 12.5 kilovolts (kV) to 34.5 kV. Customers taking Primary Service are responsible for providing the transformation of power to the voltage at which it is to be used by the Customer.

Transmission Service is service taken at 44 kV or higher. Customers taking Transmission Service are responsible for providing the transformation of power to the voltage at which it is to be used by the Customer.

RULE C
SERVICE AND LIMITATIONS

1. Rates and Tariff. Service supplied by the Company will be in accordance with the Tariff on file with the state regulatory authority having jurisdiction, and as in effect at the time service is supplied. All service rates and agreements are subject to the continuing jurisdiction and regulation of such authority, as provided by law. Those matters relating to customer service not expressly addressed in the Rules, Regulations, and Rates of this Tariff shall conform to the requirements of Oregon Administrative Rules, Chapter 860, Division 21.

When any municipal corporation or other local taxing agency imposes on the Company any franchise, occupation, sales, license, excise, business, operating, privilege, or use of street tax or exaction, the amount thereof which exceeds 3 1/2 percent of the gross revenue (pursuant to OAR 860-22-0040) derived from Electric Service furnished Customers within the levying municipality or taxing district will be billed pro rata to such Customers in accordance with Schedule 95. When Customers are billed as herein provided, the amount will be separately stated on, and added to, the regular billing.

2. Supplying of Service. Service will be supplied under a given schedule only to Points of Delivery as are adjacent to facilities of the Company, adequate and suitable as to capacity and voltage for the service desired and under the schedule applicable thereto. The Company will not be obligated to construct extensions or install additional service facilities except in accordance with Rule H. In all other cases, special agreements between the Customer and the Company may be required.

3. Service Application. The Company will normally accept an application for service from the Customer by telephone, through the Company's Web site or by other oral communication. The Company may however, at its discretion, require the Customer to sign an application requesting service. As provided in OAR 860-021-0055, applications for temporary, seasonal, or short-term service for periods of not less than one month are accepted when the Company has available capacity for the service required and the Customer pays the Company in advance the estimated net cost of installing and removing the facilities required to supply service.

4. Choice of Schedules. The Company's schedules are designed to provide monthly rates for service supplied to the Customer on an annual basis. The Customer may elect to take service under any of the schedules applicable to this annual service requirement, and the Company will endeavor to assist in the selection of the appropriate schedule most favorable to the Customer. Changing of schedules will occur only when the characteristics of the Customer's usage change such that another applicable schedule is deemed more favorable to the Customer when applied to the Customer's annual service requirements. Customers receiving service under Schedules 7, 9, and 19 will be reviewed on a monthly basis under the provisions established in the Applicability section of each of these schedules.

5. Point of Delivery Service Requirements. A Customer may be served at more than one Point of Delivery at the same Premises if practicable, unless otherwise specified in a schedule. Service at each Point of Delivery at the same Premises will be offered under the appropriate schedule. The Customer's request for service at an additional Point of Delivery will be subject to the applicable line extension rules of the Company. The Company may refuse to provide service at more than one Point of Delivery at the same Premises if it is determined by the Company that the additional Point of Delivery cannot be provided without jeopardizing the safety and reliability of the Company's system or service to the Customer or to other Customers. Service provided to a Customer at multiple Points of Delivery at the same Premises will not be interconnected electrically.

RULE C
SERVICE AND LIMITATIONS
(Continued)

Point of Delivery Service Requirements (Continued)

Where separate Points of Delivery exist for supplying service to a Customer at a single Premises or separate meters are maintained for measurement of service to a Customer at a single Premises, the meter readings will not be combined or aggregated for any purpose except for determining if the Customer's total power requirement exceeds 20,000 kW. Special contract arrangements will be required when a Customer's aggregate power requirement exceeds 20,000 kW.

Service delivered at low voltage (600 volts or under) will be supplied from the Company's distribution system to the outside wall of the Customer's building or service pole, unless an exception is granted by the Company and the City or State Electrical Inspector.

The Customer's facilities will be installed and maintained in accordance with the requirements of the National Electrical Code.

6. Limitation of Use. A Customer will not resell electricity received from the Company to any person except where the Customer is owner, lessee, or operator of an apartment house, mobile home court, or other multi-family dwelling where the use has been sub-metered prior to January 1, 1974, and the use is billed to residential tenants at the same rates that the Company would charge for service, unless the Commission authorizes alternative procedures.

A Customer's wiring will not be extended or connected to furnish service to more than one building or place of use through one meter, even though such building, property, or place of use is owned by the Customer. This rule is not applicable where the Customer's business consists of one or more adjacent buildings or places of use located on the same Premises or operated as an integral unit, under the same name and carrying on parts of the same business.

7. Rights of Way. The Customer shall, without cost to the Company, grant the Company a right of way for the Company's lines and apparatus across and upon the property owned or controlled by the Customer, necessary or incidental to the supplying of Electric Service and shall permit access thereto by the Company's employees at all reasonable hours.

RULE D
METERING

1. Meter Installations. The Company will install and maintain the metering equipment required by the Company to measure power and energy supplied to the Customer. Meter installations will be done at the Company's expense except as specified below or otherwise specified in a schedule. Customer provisions for meter installations will be made in conformance with Company specifications, the National Electrical Code, and/or applicable state or municipal requirements.

a. Instrument Transformer Metering. When instrument transformer metering is requested by the Customer but not required by the Company at the time of the initial meter installation, the Customer will be required to pay the cost of such metering equipment and its installation in accordance with the charges specified in Schedule 66. When a Customer requests instrument transformer metering not required by the Company at a time other than at the time of the initial meter installation, the actual costs will apply.

b. Off-Site Meter Reading Service. Customers taking single-phase service under Schedule 1 or Schedule 7 may request the Company install metering equipment which provides for off-site meter reading. The installation fee and monthly charges for off-site meter reading capability, when the service is requested by the Customer but not deemed to be cost-effective by the Company, are specified in Schedule 66. The Company shall have the sole right to determine whether an installation is cost-effective. Customers who request the Company-installed off-site meter reading equipment be removed within 90 days of initial installation will be assessed a removal fee in accordance with the provisions of Schedule 66. Due to the specialized nature of the metering equipment, a delay may occur between the time a Customer requests the Off-Site Meter Reading Service and the time the equipment is available for installation. Customers utilizing the Off-Site Meter Reading Service may be required to periodically permit Company personnel access to the meter in order for maintenance to be performed.

c. Load Profile Metering. The Company will install, at the Customer's request, the metering equipment necessary to provide load profile information. The installation fee and monthly charges for load profile capability, when the service is requested by the Customer but not provided by the Company as part of the standard meter installation, are specified in Schedule 66. The options available under the Load Profile Metering Service include Meter Pulse Output Service and Load Profile Recording Service. Customers requesting the Load Profile Recording Service are responsible for providing, at their own expense, a hard-wired phone line to each metering point. Customers who request the Load Profile Metering Service be discontinued within 36 months of initial installation will be assessed a removal fee in accordance with the provisions of Schedule 66.

d. Surge Protection Device Services. At the Customer's request, the following services are available for watt-hour metered Customers only.

i. Installation or Removal. The Company will install or remove, at the Customer's request, a surge protection device supplied by the Customer on the meter base and other utility peripherals to accommodate whole-house surge protection. A Surge Protection Device Installation or Removal Charge will be assessed as specified in Schedule 66.

The Company will not install any surge protection device without proof that the vendor of the surge protection device has executed and delivered to the Company an agreement (in a form acceptable to the Company) which provides for the full defense and indemnification of the Company by the vendor against any claims, suits, or losses associated with such device.

RULE D
METERING
(Continued)

d. Surge Protection Device Services (Continued)

Any surge protection device the Company is requested to install on the meter must be Underwriters' Laboratories, Inc. certified and meet National Electric Energy Testing, Research and Application Centers (NEETRAC) test standards or comparable test standards.

ii. Surge Protection Device Customer Visit Charge.

(1) If a surge protection device installation visit results in the inability of Company personnel to install the surge protection device due to safety concerns, inaccessibility to the meter base or other utility access points, or other factors deemed reasonable by the Company, a Surge Protection Device Customer Visit Charge will be applied as specified in Schedule 66. The Company has the sole right to ultimately determine installation feasibility.

(2) Customers who request the Company perform an on-site visit to assess alleged electrical problems believed to be associated with the surge protection product will be charged a Surge Protection Device Customer Visit Charge as specified in Schedule 66 if no problems associated with the electrical service are found as a result of the visit.

e. Primary Voltage Metering. The Company will install, at its own expense, a maximum of one primary voltage meter at a single Premises to record usage taken at 12.5 kV or 34.5 kV.

2. Measurement of Energy. Except as otherwise specifically provided, all energy delivered by the Company will be billed according to measurement by meters located at or near the Point of Delivery.

If the Company is unable to read a Customer's meter because of reasons beyond the Company's control, such as weather conditions or the inability to obtain access to the Customer's Premises, the Company may estimate the meter reading for the Billing Period on the basis of the Customer's previous use, season of the year and use by similar Customer's of the same class in that service area. Bills rendered on estimated readings will be so designated on the bill. The amount of such estimated bill will be subsequently adjusted, as necessary, when the next actual reading is obtained.

Should the Company be unable to read a Customer's meter for two consecutive Billing Periods, the Company will diligently attempt to contact the Customer by telephone and/or letter, to apprise the Customer of the necessity of a meter reading and to make arrangements to read the meter or request the Customer to record and return the meter reading on a card provided by the Company. If such arrangements cannot be made or if the Customer fails to return the meter reading card, the Company may estimate the meter reading.

3. Failure to Register. If the Company's meters fail to register at any time, the service delivered and energy consumed during such period of failure will be determined by the Company on the basis of the best available data. If any appliance or wiring connection, or any other device, is found on the Customer's Premises which prevents the meters from accurately recording the total amount of energy used on the Premises, the Company may at once remove any such wiring connection or appliance, or device, at the Customer's expense, and will estimate the amount of energy so consumed and not registered as accurately as it is able so to do, and the Customer will pay for any such energy within 5 days after being billed, in accordance with such estimate.

RULE D
METERING
(Continued)

4. Meter Tests. The Company will test and inspect its meters from time to time and maintain their accuracy of registration in accordance with generally accepted practices and with OAR 860-023-0015. The Company will, without charge, test the accuracy of registration of a meter upon request of a Customer, provided that the Customer does not request such a test more frequently than once in a 12-month period. If more than one requested test is performed within a 12-month period, the Customer will be required to pay in advance the estimated cost of a special meter test as specified in Schedule 66. The Company will refund the amount paid by the Customer for the test if the results of the test show the average registration error of the meter exceeds ± 2 percent.

5. Transformer Losses. When delivery of service is on the primary side of the Customer's transformers, the Company may install its meters on the secondary side of the transformers, and, unless otherwise provided in the schedule, in determining the monthly consumption of power and energy, transformer losses and other losses occurring between the Point of Delivery and the meters will be computed and added to the reading of such meters.

6. Meter Reading. Meters will be read to the last kWh registered, normally at intervals of approximately 30 days. In no case will the meter reading interval exceed 45 days.

RULE E

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RULE F
SERVICE ESTABLISHMENT AND DISCONTINUANCE

1. Service Establishment. A Service Establishment Charge as specified in Schedule 66, unless otherwise specified in a different schedule, will be assessed upon initiating metered service with the Company if service at the Point of Delivery is currently energized. The applicable charge will be billed with the first regular bill.

    a. Owners or managers of rental property that arrange with the Company to provide continuous service between tenants will not be assessed a Service Establishment Charge when the service reverts to the responsible party as arranged.

2. Continuous Service. At the request of owners or managers of rental property, the Company will provide continuous service between tenant occupancy. Continuous Service Reversion Charge, as specified in Schedule 66, will be assessed each time the service reverts to the responsible party as arranged.

3. Service Connection. Where service at the specified Point of Delivery is currently disconnected from the Company's system, a Service Connection Charge as specified in Schedule 66 will be assessed at the time service is connected. The Service Connection Charge applies to all service connections for both metered and unmetered service and will be billed with the first regular bill. The Service Establishment Charge does not apply when service is reconnected.

4. Service Discontinuance. At the Customer's request, the Company will disconnect service during normal working hours. There is no charge for discontinuing service.

    a. When a Customer requests service be discontinued, service will not be disconnected if another party has agreed to accept responsibility for service at the Point of Delivery. Upon initiating service, the Customer requesting service will be billed a Service Establishment Charge in accordance with this rule.

5. Termination Practices. The Company's practices relating to Termination of Service are governed by the Oregon Administrative Rules (OAR) of the Oregon Public Utility Commission, in effect at the time the event occurred which required application of the OAR. If the Company's Rules and Regulations on file with the Oregon Public Utility Commission contain provisions which conflict with the OAR, the provisions of the OAR supersede those included in the Company's Rules and Regulations.

6. Field Visit. A Field Visit Charge, as specified in Schedule 66, will be assessed when a Company representative visits a service address intending to disconnect or connect service, but due to Customer action, the Company representative is unable to complete the disconnection or connection at the time of the visit.

7. Unauthorized Reconnection. Where damage to the Company's facilities has occurred due to tampering or where reconnection of service has been made by other than the Company, an Unauthorized Reconnection Charge may be collected as specified in Schedule 66. This charge is not a waiver by the Company of the rights to recover losses due to tampering. In addition to the above-mentioned charge, the Customer receiving service shall be liable for any damage to Company property.

RULE G
BILLINGS

1. Fractional Periods. When the Customer's Billing Period is less than 27 days or greater than 36 days, the Energy Charge for service under Schedules 1, 7, 9, 19, or 24 the Energy Charge will be calculated using actual meter readings. The Energy Charge for services provided under Schedule 40 will be determined using the daily kWh calculated on the basis of load size and number of units served multiplied by the actual number of days since the account was opened or since the previous billing, where appropriate. The proration of the applicable Demand Charge, Basic Charge, Facilities Charge, and Service Charge specified in the appropriate schedule will be calculated by dividing the charge by 30 and multiplying the result by the actual number of days since the account was opened or since the previous meter reading, where appropriate. However, the prorated Service Charge for Schedules 1, 7, 9, 19, or 24 or the Minimum Charge for Schedule 40, will be no less than the amount specified in Schedule 66. For Schedule 15, the proration of the applicable Monthly Charge will be calculated by dividing the charge by 30 and multiplying the result by the actual number of days since the account was opened or the previous billing, where appropriate; however, in no event will the charge be less than the Fractional Period Minimum Billings amount specified in Schedule 66.

2. Corrected Billings. Whenever it is determined that a Customer was billed under an inappropriate schedule, the Customer will be rebilled under the appropriate schedule, except if the Company selected the schedule on the basis of available information and acted in good faith, the Company will not be required to rebill or adjust billings. The rebilling period will be no more than the 3-year period as provided by OAR 860-021-0135.

If the average error for any meter test exceeds ± 2 percent, corrected billings will be prepared. The corrected billings will not exceed 6 months if the time when the malfunction or error began is unknown. If the time when the malfunction or error began is known, the corrected billings will be from that time, but will not exceed the 3 year period as provided by OAR 860-021-0135. The Company shall provide written notice to the Customer detailing the circumstances, time period, and adjustment amount of an over or underbilling. If an underbilling occurs, the Company will offer and enter into reasonable payment arrangements with the Customer. The Customer shall be notified in writing of the opportunity for time payments and of the Commission's dispute resolution process. For any overbillings, the Customer will have the choice of a refund or a credit on future bills.

3. Due Dates. The Company's practices relating to Due Dates are governed by the Oregon Administrative Rules (OAR) of the Oregon Public Utility Commission, in effect at the time the event occurred which required application of the OAR. If the Company's Rules and Regulations on file with the Oregon Public Utility Commission contain provisions which conflict with the OAR, the provisions of the OAR supersede those included in the Company's Rules and Regulations.

4. Returned Checks. Checks or payments remitted by Customers in payment of bills are accepted conditionally. A Returned Check Charge, as specified in Schedule 66, will be assessed the Customer for handling each check or payment upon which payment has been refused by the bank.

5. Temporary Suspension of Demand. When the Customer is obliged temporarily to suspend operation due to strikes, action of any governmental authority, acts of God or the public enemy, the Customer may procure a proration of the monthly Billing Demand based upon the period of such suspension by giving immediate written notice to the Company. However, all monthly Minimum Charges and/or obligations will continue to apply as specified in the applicable schedule or a written agreement.

RULE H
NEW SERVICE ATTACHMENTS AND DISTRIBUTION LINE INSTALLATIONS OR ALTERATIONS

This rule applies to requests for electric service under Schedules 1, 7, 9, 19, and 24, that require the installation, alteration, relocation, removal, or attachment of Company-owned distribution facilities. New construction beyond the Point of Delivery for Schedule 9 or Schedule 19 is subject to the provisions for facilities charges under those schedules. This rule does not apply to transmission or substation facilities, or to requests for electric service that are of a speculative nature.

1. Definitions

Additional Applicant is a person or entity whose Application requires the Company to provide new or relocated service from an existing section of distribution facilities with a Vested Interest.

Applicant is a person or entity whose Application requires the Company to provide new or relocated service from distribution facilities that are free and clear of any Vested Interest.

Application is a request by an Applicant or Additional Applicant for new electric service from the Company. The Company, at its discretion, may require the Applicant or Additional Applicant to sign a written application.

Company Betterment is that portion of the Work Order Cost of a Line Installation, alteration, and/or Relocation that provides a benefit to the Company not required by the Applicant or Additional Applicant. Increases in conductor size and work necessitated by the increase in conductor size are considered a Company Betterment if the Connected Load added by the Applicant or Additional Applicant is less than 100 kilowatts. If, however, in the Company's discretion, it is determined that the additional Connected Load added by the Applicant or Additional Applicant, even though less than 100 kilowatts, is (1) located in a remote location, or (2) a part of a development or project which will add a load greater than 100 kilowatts, the Company will not consider the work necessitated by the load increase to be a Company Betterment.

Connected Load is the total nameplate kW rating of the electric loads connected for commercial, industrial, or irrigation service. Connected Load for residences is considered to be 25 kW for residences with electric space heat and 15 kW for all other residences.

Fire Protection Facilities are water pumps and other fire protection equipment, served separately from the Applicant's other electric load, which operate only for short periods of time in emergency situations and/or from time to time for testing purposes.

Line Installation is any installation of new distribution facilities (excluding Relocations or alteration of existing distribution facilities) owned by the Company.

Line Installation Allowance is the portion of the estimated cost of a Line Installation funded by the Company.

Line Installation Charge is the partially refundable charge assessed an Applicant or Additional Applicant to be paid to the Company prior to the construction of the Line Installation, in accordance with Section II.I. "Terms of Payment".

RULE H
NEW SERVICE ATTACHMENTS AND
DISTRIBUTION LINE INSTALLATIONS
OR ALTERATIONS
(Continued)

1. Definitions (Continued)

Multiple Occupancy Projects are projects that are intended to be occupied by more than four owners or tenants. Examples include, but are not limited to, condominiums and apartments.

Relocation is a change in the location of existing distribution facilities.

Residence is a structure built primarily for permanent domestic dwelling. Dwellings where tenancy is typically less than 30 days in length, such as hotels, motels, camps, lodges, clubs, and structures built for storage or parking do not qualify as a Residence.

Subdivision is the division of a lot, tract, or parcel of land into two or more parts for the purpose of transferring ownership or for the construction of improvements thereon, that is lawfully recognized and approved by the appropriate governmental authorities.

Temporary Line Installation is a Line Installation for electric service of 18 calendar months or less in duration.

Temporary Service Attachment is a service attachment to a Customer provided temporary pole which typically furnishes electric service for construction.

Terminal Facilities include transformer, meter, service cable, and underground conduit (where applicable).

Underground Service Attachment Charge is the non-refundable charge assessed an Applicant or Additional Applicant whenever new single phase underground service is required by a Schedule 1 or Schedule 7 customer attaching to the Company's distribution system.

Unusual Conditions are construction conditions not normally encountered. These conditions may include, but are not limited to: frost, landscape replacement, road compaction, pavement replacement, chip-sealing, rock digging, boring, nonstandard facilities or construction practices, and other than available voltage requirements.

Vested Interest is the right to a refund that an Applicant or Additional Applicant holds in a specific section of distribution facilities when Additional Applicants attach to that section of distribution facilities.

Vested Interest Charge is an amount collected from an Additional Applicant for refund to a Vested Interest Holder.

Vested Interest Holder is a person or an entity that has paid a refundable Line Installation Charge to the Company for a Line Installation under either the provisions of the existing Rule H or the provisions of a previous Rule H whichever is applicable as per the Existing Agreements provisions of this rule.

RULE H
NEW SERVICE ATTACHMENTS AND
DISTRIBUTION LINE INSTALLATIONS
OR ALTERATIONS
(Continued)

1. Definitions (Continued)

Vested Interest Refund is a refund payment to an existing Vested Interest Holder resulting from a Vested Interest Charge to an Additional Applicant.

Vested Interest Portion is that part of the Company's distribution system in which a Vested Interest is held.

Work Order Cost is a cost estimate performed by the Company for a specific request for service by an Applicant or Additional Applicant. The Applicant or Additional Applicant shall be responsible for the costs associated with the overhead construction, including, but not limited to, poles, conductors, transformers, meters, and any required permits, less applicable Line Installation Allowances. The Applicant or Additional Applicant shall be responsible for the costs associated with the underground construction, including, but not limited to, conduit, trenching, boring, excavating, backfilling, ducts, raceways, road crossings, paving, vaults, transformers, transformer pads, conductors, meters, and any required permits, less applicable Line Installation Allowances. The Work Order Cost will include general overheads limited to 1.5 percent. General overheads in excess of 1.5% will be funded by the Company.

2. General Provisions

a. Cost Information - The Company will provide cost information as reflected in the charges contained in this rule, to potential Applicants and/or Additional Applicants. This preliminary information will not be considered a formal cost quote and will not be binding on the Company or Applicant but rather will assist the Applicant or Additional Applicant in the decision to request a formal cost quote. Upon receiving a request for a formal cost quote, the Applicant or Additional Applicant will be required to prepay non-refundable engineering costs to the Company.

b. Ownership - The Company will own all distribution Line Installations and retain all rights to them.

c. Rights-of-Way - The Company will construct, own, operate, and maintain lines only along public streets, roads, and highways that the Company has the legal right to occupy, and on public lands and private property across which rights-of-way satisfactory to the Company may be obtained at the Applicant's or Additional Applicant's expense.

d. Removals - The Company reserves the right to remove any distribution facilities that have not been used for one year. Facilities shall be removed only after providing 60 days written notice to the last Customer of record and the owner of the property served, giving them a reasonable opportunity to respond.

e. Property Specifications - Applicants or Additional Applicants must provide the Company with final property specifications as required and approved by the appropriate governmental authorities. These specifications may include but are not limited to: recorded plat maps, utility easements, final construction grades, and property pins.

RULE H
NEW SERVICE ATTACHMENTS AND
DISTRIBUTION LINE INSTALLATIONS
OR ALTERATIONS
(Continued)

2. General Provisions (Continued)

f. Undeveloped Subdivisions - When electric service is not provided to the individual spaces or lots within a Subdivision, the Subdivision will be classified as undeveloped.

g. Mobile Home Courts - Owners of mobile home courts will install, own, operate, and maintain all termination poles, pedestals, meter loops, and conductors from the Point of Delivery.

h. Conditions for Start of Construction - Construction of the Line Installations and/or Relocations will not be scheduled until the Applicant or Additional Applicant pays the appropriate charges to the Company. Appropriate charges include, but are not limited to, engineering fees, work order costs, right-of-way or permit charges, and vested interest payments.

i. Terms of Payment – All payments listed under this section will be paid to the Company in cash 30 days prior to the start of Company construction, unless mutually agreed otherwise.

j. Interest on Payment - If the Company does not start construction on a Line Extension and/or Relocation within 30 days after receipt of the construction payment, the Company will compute interest on the payment amount beginning on the 31st day and ending once Company construction actually begins. Interest will be computed at the rate applicable under the Company's Rule F. If this computation results in a value of $10.00 or more, the Company will pay such interest to the Applicant, Additional Applicant, or subdivider. Construction payment includes, but is not limited to, payment for work order costs, right-of-way or permit charges, and vested interest payments.

k. Fire Protection Facilities - The Company will provide service to Fire Protection Facilities when the Applicant pays the full costs of the Line Installation including Terminal Facilities, less Company Betterment. These costs are not subject to a Line Installation Allowance, but are eligible for Vested Interest Refunds under Section 6.a.

l. Customer Provided Trench Digging and Backfill - The Company will at its discretion allow an Applicant, Additional Applicant or subdivider to provide trench digging and backfill. The Customer will sign a Memorandum of Agreement, detailing the work to be performed by the Customer and the specifications that must be met prior to the start of construction. The Applicant shall be responsible for the current and reasonable future costs associated with the Line Installation's conduit system, which may include, but is not limited to, the costs of trenching, boring, excavating, backfilling, ducts, raceways, road crossings, paving, vaults, transformer pads, and any required permits. The Company shall own and maintain the conduit system once Company conductors have been installed. In a joint trench, backfill must be provided by the Company. Costs of Customer provided trench and backfill will be removed or not included in the Work Order Costs and will not be subject to refund.

RULE H
NEW SERVICE ATTACHMENTS AND
DISTRIBUTION LINE INSTALLATIONS
OR ALTERATIONS
(Continued)

3. Line Installation Allowances

The Company will contribute an allowance for the Terminal Facilities necessary for service attachments and/or Line Installations. A Line Installation Allowance will be applied to the Line Installation costs for a Subdivision as outlined in Section 4.a.i. Subdividers may recoup their payments only through the refunding provisions under Section 6 of this rule.

	Maximum Allowance
Schedule 1	
Residence	Overhead Terminal Facilities + $1000
Non-Residence	Cost of Meter Only
Multiple Occupancy Projects	
Single Phase	Overhead Terminal Facilities
Three Phase	80% of Terminal Facilities
Schedule 7	
Single Phase	Overhead Terminal Facilities
Three Phase	80% of Terminal Facilities
Schedule 9	
Single Phase	$1726
Three Phase	80% of Terminal Facilities
Schedule 24	
Single Phase	$1726
Three Phase	Overhead Terminal Facilities
Schedule 19	
Secondary Service	No Allowances
Primary Service	No Allowances
Transmission Service	No Allowances

4. Charges for Line Installations and Additional Charges for Underground Service Attachments

An Applicant or Additional Applicant will pay the Company for construction of Line Installations and/or underground service attachments, less Line Installation Allowances, based upon the charges listed in this section.

a. Line Installation Charge

If a Line Installation is required, the Applicant or Additional Applicant will pay a partially refundable Line Installation Charge equal to the Work Order Cost less applicable Line Installation Allowances. The Line Installation Charge will be paid to the Company in cash 30 days prior to the start of Company construction, unless mutually agreed otherwise.

RULE H
NEW SERVICE ATTACHMENTS AND
DISTRIBUTION LINE INSTALLATIONS
OR ALTERATIONS
(Continued)

4. Charges for Line Installations and Additional Charges for Underground Service Attachments (Continued)

Inside a Residential Subdivision, the Line Installation Charges are calculated using the Work Order Cost less Terminal Facilities. If a developer is installing the final primary or secondary line to serve the Customer, the developer is entitled to the Terminal Facilities allowance and an $800 lot refund when a permanent residential connection is made on the lot. If the lot purchaser is making the final primary or secondary line installation, the lot purchaser is entitled to the Terminal Facilities allowance, if needed, and up to $800 applied to the Line Installation costs. The developer will not receive the $800 lot refund to the extent an allowance has been given to a lot purchaser. The maximum refund will be the total per lot refund amount as specified in Section 6.b., but not more than the Work Order Cost less Terminal Facilities. Costs of new facilities outside Subdivisions are subject to Vested Interest Refunds. Costs of new Line Installations inside Subdivisions are not subject to Vested Interest Refunds.

Inside a non-Residential Subdivision, the subdivider is required to pay for the installation of the backbone with no allowances. The applicable Terminal Facilities allowance is provided to the Customer requesting service to the lot. The applicable Terminal Facilities allowances are as follows:

	Maximum Allowance
Schedule 7	
Single Phase	Overhead Terminal Facilities
Three Phase	80% of Terminal Facilities
Schedule 9	
Single Phase	Overhead Terminal Facilities
Three Phase	80% of Terminal Facilities

b. Underground Service Attachment Charge

Each Applicant or Additional Applicant will pay a non-refundable Underground Service Attachment Charge for attaching new Terminal Facilities to the Company's distribution system. The Company will determine the location and maximum length of service cable.

RULE H
NEW SERVICE ATTACHMENTS AND
DISTRIBUTION LINE INSTALLATIONS
OR ALTERATIONS
(Continued)

4. Charges for Line Installations and Additional Charges for Underground Service Attachments (Continued)

b. Underground Service Attachment Charge (Continued)

Schedule 1, 7, and 9 Single Phase (Limited to a maximum of 400 Amps

Underground Service Cable	
(Base Charge plus Distance Charge)	
Base Charge	
from underground	$40.00
from overhead including 2" riser	$395.00
from overhead including 3" riser	$520.00
Distance Charge (per foot)	
Company Installed Facilities (per foot)	
with 1/0 underground cable	$6.90
with 4/0 underground cable	$7.50
with 350 underground cable	$9.60
Customer Provided Trench & Conduit (per foot)	
with 1/0 underground cable	$2.15
with 4/0 underground cable	$3.60
with 350 underground cable	$4.65

c. Vested Interest Charge

Additional Definitions for Section 4.c. and Section 6.a.:

Original Investment - Work Order Cost less the Allowance for Terminal Facilities.

Vested Interest Holder's Contribution - Customer Payment plus Line Installation Allowances other than Terminal Facilities.

Vested Interest - Amount potentially subject to refund.

Load Ratio - Additional Applicant load divided by the sum of Additional Applicant's load and Vested Interest Holder's load.

Distance Ratio - Additional Applicant distance divided by original distance.

i. The initial Applicant will pay the original investment cost less any allowances. An Additional Applicant connecting to a Vested Interest Portion will have two options:

Option One - An Additional Applicant may choose to pay the current Vested Interest Holder's Vested Interest, in which case the Additional Applicant will become the Vested Interest Holder and, as such, will become eligible to receive Vested Interest Refunds up to that new Vested Interest Holder's contribution less 20 percent of the original investment.

RULE H
NEW SERVICE ATTACHMENTS AND
DISTRIBUTION LINE INSTALLATIONS
OR ALTERATIONS
(Continued)

4. Charges for Line Installations and Additional Charges for Underground Service attachments (Continued)

Option Two – An additional Applicant may choose to pay an amount determined by this equation:

Vested Interest payment = Load Ratio x distance Ratio x Vested Interest Holder's unrefunded contribution.

c. Vested Interest Charge (Continued)

If Option Two is selected, the Additional Applicant has NO vested Interest and the previous Vested Interest Holder remains the Vested Interest Holder. The Vested Interest Holder's Vested Interest will be reduced by the newest Additional Applicant's payment.

ii. The Vested Interest Charge will not exceed the sum of the Vested Interests in the Vested Interest Portion.

iii. If an Additional Applicant connects to a Vested Interest Portion which was established under a prior rule or schedule, the Vested Interest Charges of the previous rule of schedule apply to the Additional Applicant.

5. Other Charges

All charges in this section are non-refundable.

a. Relocation and Removal Charges – If an Applicant or Additional applicant requests a Relocation or removal of Company facilities, the Applicant or Additional applicant will pay a non-refundable charge equal to the Work Order Cost.

b. Engineering Charge – Applicants or Additional Applicants will be required to prepay all engineering costs for Line Installations, and/or Relocation. Engineering charges will be calculated at $44.00 per hour.

c. right-of-Way Charge – A pplicants or Additional Applicants will be responsible for any costs associated with the acquisition of right-of-way.

d. Temporary Line Installation Charge – Applicants or Additional Applicants will pay the installation and removal costs of providing Temporary Line Installations.

e. Temporary Service Attachment Charge – Applicants or Additional Applicants will pay for Temporary Service Attachments as follows:

i. Underground - $140.00

The Customer provided pole must be set within two linear feet of the Company's existing transformer or junction box.

RULE H
NEW SERVICE ATTACHMENTS AND
DISTRIBUTION LINE INSTALLATIONS
OR ALTERATIONS
(Continued)

5. Other Charges (Continued)

e. Temporary Service Attachment Charge (Continued)

ii. Overhead - $120

The Customer provided pole shall be set in a location that does not require more than 100 feet of #2 aluminum service conductor that can be readily attached to the permanent location by merely relocating it.

The electrical facilities provided by the Customer on the pole shall be properly grounded, electrically safe, and ready for connection to Company facilities.

The Customer shall obtain all permits required by the applicable state, county, or municipal governments and will provide copies or verification to the Company as required. The above conditions must be satisfied before the service will be attached. Refer to Schedule 66 Temporary Service Return Trip for charges if these conditions are not satisfied.

f. Unusual Conditions - Applicants, Additional Applicants, and subdividers will pay the Company the additional costs associated with any Unusual Conditions included in the Work Order Cost related to the construction of a Line Installation or Relocation. This payment, or portion thereof, will be refunded to the extent that the Unusual Conditions are not encountered. Unusual Conditions payments for Line Installations will also be refunded, under the provisions of Section 6l, if the Unusual Conditions are encountered.

In the event that the estimate of the Unusual Conditions included in the Work Order Cost exceeds $10,000, the Applicant, Additional Applicant or subdivider may either pay for the Unusual Conditions or may furnish an Irrevocable Letter of Credit drawn on a local bank or local branch office issued in the name of Idaho Power Company for the amount of the Unusual Conditions. Upon completion of that portion of the project which included an Unusual Conditions estimate, Idaho Power Company will bill the Applicant, Additional Applicant or subdivider for the amount of Unusual Conditions encountered up to the amount established in the Irrevocable Letter of Credit. The Applicant, Additional Applicant or subdivider will have 15 days from the issuance of the Unusual Conditions billing to make payment. If the Applicant, Additional Applicant or subdivider fails to pay the Unusual Conditions bill within 15 days, Idaho Power will request payment from the bank.

g. Joint Trench - Applicants, Additional Applicants, and subdividers will pay the Company for trench and backfill costs included in the work order prepared for an unshared trench. In the event that the Company is able to defray any of the trench and backfill costs included in the work order through the sharing of the trench with other utilities, the trench and backfill cost savings will be refunded.

RULE H
NEW SERVICE ATTACHMENTS AND
DISTRIBUTION LINE INSTALLATIONS
OR ALTERATIONS
(Continued)

6. Refunds

a. Vested Interest Refunds - The initial Applicant will be eligible to receive up to 80 percent of the original investment as a Vested Interest Refund in accordance with Section 4.c. Refunds will be funded by the Additional Applicant's Vested Interest Charge as calculated in accordance with Section 4.c. A Vested Interest Holder and the Company may agree to waive the Vested Interest payment requirements of Additional Applicants with loads less than an agreed upon level. Waived Additional Applicants would not be considered Additional Applicants for purposes of Section 6.a.i.(a).

i. Vested Interest Refund Limitations

(1) Except for Rule 6.c. Vested Interest Refunds will be funded by no more than four Additional Applicants during the 5 year period following the completion date of the Line Installation for the initial Applicant.

(2) In no circumstance will refunds exceed 100 percent of the refundable portion of any party's cash payment to the Company.

b. Subdivision Refunds

i. A subdivider will be eligible for Vested Interest Refunds for payments for Line Installations outside the subdivision.

ii. A subdivider will be eligible for a refund from the Company on the Line Installation Charge inside the Subdivision when a permanent Residence connects for service and occupies a lot inside the Subdivision within 5 years from the construction completion date of the Line Installation for the Subdivision.

iii. The amount refunded to subdividers of residential Subdivisions will be $800 per lot, less any additional Line Installation costs required to provide connected service to the lot.

7. Line Installation Agreements

When the Line Installation Allowance paid by the Company under the provisions of this rule equals or exceeds $75,000, the Applicant will be required to contract to pay, for a period of 5 years following the completion date of the Line Installation, an annual payment equal to the greater of the billings determined by application of the appropriate schedule or:

a. Eighty percent of the Applicant's total annual bill as determined by application of the appropriate schedule; plus;

RULE H
NEW SERVICE ATTACHMENTS AND
DISTRIBUTION LINE INSTALLATIONS
OR ALTERATIONS
(Continued)

7. Line Installation Agreements (Continued)

b. Twenty percent of the Line Installation Allowance granted the Applicant.

Each Line Installation, for which the Line Installation Allowance paid equals or exceeds $75,000, will require a separate Uniform Distribution Line Installation Agreement between the Applicant and the Company.

Developers of multi-family residential dwellings in which each unit is separately metered will be exempt from the requirement to enter into an agreement with the Company if the Line Installation Allowance paid equals or exceeds $75,000.

8. Existing Agreements

This rule shall not cancel existing agreements, including vested interest payments and refund provisions, between the Company and previous Applicants, or Additional Applicants. All applications of Additional Applicants will be governed and administered under the rule or schedule in effect at the time the original Application was received and dated by the Company.

If an Additional Applicant requires the installation of new or altered distribution facilities, the Additional Applicant will also be the Original Applicant for the new or altered distribution facilities. As the Original Applicant, the payment for such new or altered distribution facilities will be subject to the rule in effect at the time of the Additional Applicant's Application for new or altered distribution facilities is received and dated by the Company. Accordingly, an Additional Applicant can be simultaneously an Original Applicant with separate provisions for vested interest payments and refunds.

9. Relocation or Removal of Facilities

a. Generally - Any relocation of Facilities for a requesting party, including builders, developers, Customers or Customers' agents, that is for their convenience will be performed by the Company at the requesting party's expense. The Company may require payment in advance of a sum equal to the estimated original cost of installed facilities to be removed, less estimated salvage and less depreciation, plus estimated removal cost, plus any operating expense associated with the removal or relocation.

b. Public Works Project - Under the following circumstances, the cost for relocation or removal of facilities within the public right-of-way will be borne by the Company unless an ordinance, legislation or private agreement specifies other cost responsibilities:

i. The rearrangement can be identified to be for a public works project. Examples of public works projects include but are not limited to public transit or a road widening financed by public funds;

RULE H
NEW SERVICE ATTACHMENTS AND
DISTRIBUTION LINE INSTALLATIONS
OR ALTERATIONS
(Continued)

9. Relocation or Removal of Facilities (Continued)

b. Public Works Project (Continued)

ii. Reasonable notice is provided to the Company;

iii. The overall project can generally be scheduled during normal work hours (excluding load transfers which may need to be performed outside of normal work hours); and

iv. The public works project does not require the Company to make temporary relocations.

c. Easement - Costs for permanently relocating facilities located on an easement will be borne by the requesting party regardless of status as public works or otherwise.

d. Permit Job - Where it can be identified that the requesting party has received a permit through a city or county for work within the public right-of-way that is required for the requesting party's construction project, the requesting party is responsible for all of the costs associated with the necessary rearrangement of facilities.

e. Relocation of Overhead or Underground Facilities at Company Expense - If the necessary work can be performed by Company crews in a single trip to the requesting party's Premises during scheduled crew hours, relocation or removal of overhead or underground service distribution facilities on or adjacent to the Premises will be performed at Company expense, under the circumstances listed below. For underground relocations, the requesting party is responsible for any necessary trenching, boring, backfilling, conduit, paving, vaults and pads.

i. Such facilities are idle or will be made idle by changes in the requesting party's electrical arrangement or needs, except in the case of conversion from overhead to underground service; or

ii. The location of such facilities in the street area deprive the requesting party of reasonable ingress to or egress from the Premises, provided such facilities are not on a property line or a property line extended; or

iii. Such facilities occupy space on the requesting party's Premises that will be used for an expansion of the requesting party's building or plant; or

iv. The purpose is to relocate a meter to a more accessible location approved by the Company; or

RULE H
NEW SERVICE ATTACHMENTS AND
DISTRIBUTION LINE INSTALLATIONS
OR ALTERATIONS
(Continued)

9. Relocation or Removal of Facilities (Continued)

e. Relocation of Overhead or Underground Facilities at Company Expense (Continued)

v. Relocation of a service drop is the only work requested. If a second trip is required, no charge is made if the trip can be scheduled when Company crews are normally available and at a time convenient to the Company or, if in the opinion of the Company, a definite improvement in routing or attachment of the service wire will result. In all other circumstances the requesting party shall be charged the cost incurred by the Company to make the second trip.

f. Temporary Relocations - Where the Company is required to temporarily move its facilities either because the Company cannot move its facilities to the new permanent placement or the facilities will be returned to their former location at a later point in time, the costs of the temporary relocation will be borne by the requesting party regardless of status as public works or otherwise. A temporary relocation is defined as any relocation where the Company must move its facilities two or more times within a three-year period.

10. Conversion from Overhead to Underground Service

a. General - The Company will replace overhead facilities with underground facilities whenever such conversion is practicable and economically feasible. Customers connected by overhead distribution facilities owned by the Company that desire underground service shall comply with applicable provisions of this rule.

b. Payment for Service Changes - The party requesting conversion from overhead to underground shall pay the Company, prior to conversion, the original cost, less depreciation, less salvage value, plus removal expense of any existing overhead facilities no longer used or useful by reason of said underground system, and the costs of any necessary rearrangements, modifications, and additions to existing facilities to accommodate the conversion of facilities from overhead to underground.

c. Special Conditions - The conversion of overhead to underground facilities affecting more than one Customer shall be conditioned on the following:

i. The governing body of the city or county in which the Company's facilities are located shall have adopted an ordinance creating an underground district in the area in which both the existing and new facilities are and will be located, providing:

(1). All existing overhead communication equipment and distribution facilities in such district are removed;

RULE H
NEW SERVICE ATTACHMENTS AND
DISTRIBUTION LINE INSTALLATIONS
OR ALTERATIONS
(Continued)

10. Conversion from Overhead to Underground Service (Continued)

c. Special Conditions (Continued)

(2). Each Customer served from such electric overhead facilities shall, in accordance with the Company's rules for underground service, make all necessary electrical facility changes on said Customer's Premises in order to receive service from the Company's underground facilities as soon as available; and

(3). The Company is authorized to discontinue its overhead service on completion of the underground facilities.

ii. All Customers served from overhead facilities shall agree in writing to perform the wiring changes required on their Premises so that service may be furnished in accordance with the Company's rules regarding underground service. Such Customers must also authorize the Company to discontinue overhead service upon completion of the underground facilities.

iii. When the local government requires the Company to convert overhead facilities to underground at the Company's expense, the provisions of OAR 860-022-0046 shall apply.

iv. That portion of the overhead system that is placed underground shall not impair the utilization of the remaining overhead system.

d. Cost of Area Conversions - Area conversions may involve an allocation or assessment of costs and responsibilities among Customers. Such assessment and collection thereof will be the responsibility of a governmental unit or an association of those affected.

e. Cost of Additional Circuit Capacity - Where the Company installs an underground circuit with capacity in excess of the existing overhead, any additional cost to provide such excess circuit capacity will be at the Company's expense. Applicant cost responsibilities shall be as defined in Section B plus all reasonable costs for conduit or vault space installed to establish pathways for future circuit capacity.

RULE H
NEW SERVICE ATTACHMENTS AND
DISTRIBUTION LINE INSTALLATIONS
OR ALTERATIONS
(Continued)

IDAHO POWER COMPANY
Uniform Distribution Line Installation Agreement

DISTRICT ______________________________ ACCOUNT NO.______________________________

THIS AGREEMENT Made this __________ day of ______________________, 20_____, between ____, whose billing address is ____ hereinafter called Customer, and **IDAHO POWER COMPANY,** A corporation with its principal office located at 1221 West Idaho Street, Boise, Idaho, hereinafter called Company:

NOW THEREFORE, The parties agree as follows:

1. The Company will agree to provide facilities to supply _______ volt, ____ phase Electric Service for the Customer's facilities located at or near _____, County of _____________, State of Oregon.

2. The Customer will agree to:

   a. Make a cash advance to the Company of $________________ as the Customer's share of the investment in service facilities;

   b. Provide rights-of-way for the line extension at no cost to the Company, in a form acceptable to the Company;

   c. Pay an annual minimum charge during the first 60 months following the Initial Service Date. The annual minimum charge will be the greater of (1) the total of the schedule billings for the year or (2) $______________ plus 80 percent of the total schedule billings for the year. The total schedule billings will be computed in accordance with the rates and provisions of the schedules under which the Customer received service for that year.

3. This Agreement will not become binding upon the parties until signed by both parties.

4. The initial date of delivery of power and energy is subject to the Company's ability to obtain required labor, materials, equipment, satisfactory rights-of-way and comply with governmental regulations.

5. The term of this Agreement will be for 5 years from and after the Initial Service Date thereof.

6. This Agreement will be binding upon the respective successors and assigns of the Customer and the Company, provided however, that no assignment by the Customer will be effective without the Company's prior written consent. The Company's consent will not be unreasonably withheld.

RULE H
NEW SERVICE ATTACHMENTS AND
DISTRIBUTION LINE INSTALLATIONS
OR ALTERATIONS
(Continued)

Uniform Distribution Line Installation Agreement (Continued)

7. This Agreement is subject to valid laws and to the regulatory authority and orders, rules and regulations of the Oregon Public Utility Commission and such other administrative bodies having jurisdiction as well as Idaho Power Company's Rules and Regulations as now or may be hereafter modified and approved by the Oregon Public Utility Commission.

8. The Company's Rule H, any revisions to that rule, and/or any successor rule is to be considered as part of this Agreement.

9. In any action at law or equity commenced under this Agreement and upon which judgment is rendered, the prevailing party, as part of such judgment, will be entitled to recover all costs, including reasonable attorneys fees, incurred on account of such action.

W. O. No. ____________________________

Initial Service Date ____________________

(APPROPRIATE SIGNATURES)

RULE I
BUDGET PAY PLANS

1. Residential Budget Pay Plan - Schedule 1. A Budget Pay Plan is available to Residential Customers desiring to levelize payments for electric service. If a Customer has more than one electric service on the account, each electric service charge will be levelized individually. A Customer may sign up for the Budget Pay Plan at any time during the year. In order to be eligible for the Budget Pay Plan, the Customer's account must not be in arrears.

The levelized payment will approximate the average of 12 monthly billings based on either the historical charges, or an estimate of future charges. The Budget Pay amount for each electric service on the account will be adjusted to the next higher dollar. Budget Pay amounts will be recalculated at the 12-month (or 365-day) anniversary of the date the Customer began paying the most current Budget Pay amount(s). The new monthly payment will be the recalculated Budget Pay amount(s). A Customer's Budget Pay amount(s) may decrease, increase, or remain the same.

Customers with a negative balance in their Budget Pay Plan account at the time of recalculation will have monthly Budget Pay charges equal to the recalculated Budget Pay amount plus one-twelfth of the negative balance. At the Customer's request, a negative balance may be paid in full. Customers with a positive balance in their Budget Pay Plan account at the time of recalculation, or upon termination of the agreement after all charges for services have been paid, will be refunded at the Customer's request. If no request for refund is made, the monthly Budget Pay charges will be equal to the recalculated Budget Pay amount reduced by one-twelfth of the positive balance. Upon the Customer's request, a positive balance for one Budget Pay electric service may be transferred to the balance of another Budget Pay electric service on the account.

Any estimates furnished by the Company with such Budget Pay Plan should not be construed as a guarantee that the total actual charges will not exceed the estimates. The Company, because of rate changes or other requirements, may at any time submit a revised estimate to the Customer and require that the Customer pay the revised monthly Budget Pay installment as a condition to the continuation of the Budget Pay Plan for the Customer.

The Budget Pay amount(s) will be billed on the regular service bill each month. Once established, the Budget Pay Plan will remain in effect from year to year until the Customer notifies the Company not less than 30 days prior to the desired date of cancellation or unless the Customer fails to pay the agreed amounts.

2. Small General Service Budget Pay Plan - Schedule 7. A Budget Pay Plan is available to Small General Service Customers receiving service on Schedule 7. If a Customer has more than one electric service on the account, each electric service will be levelized individually. If a Customer transfers to another schedule (other than Schedule 1), the Budget Pay Plan will not be available. A Customer may sign up for the Budget Pay Plan at any time during the year.

In order to qualify, the Customer must have been receiving service at the same location, under the same ownership and account number, and with all monthly billings paid on or before the past due date for at least 12 months prior to applying for the Budget Pay Plan. The Customer must maintain the payment status as described above or the Customer will be removed from the Budget Pay Plan on the next monthly billing and all past due balances will become immediately due and payable.

RULE I
BUDGET PAY PLANS
(Continued)

Small General Service Budget Pay Plan - Schedule 7 (Continued)

The levelized payment will approximate the average of 12 monthly billings based on historical charges. Budget Pay amounts will be recalculated at the 12-month (or 365-day) anniversary of the date the Customer began paying the most current Budget Pay amount(s). The Budget Pay amount for each electric service on the account will be adjusted to the next higher dollar. The new monthly payment will be the recalculated Budget Pay amount(s). A Customer's Budget pay amount(s) may decrease, increase, or remain the same.

Customers with a negative balance in their Budget Pay Plan account at the time of recalculation will have monthly Budget Pay charges equal to the recalculated Budget Pay amount plus one-twelfth of the negative balance. At the Customer's request, a negative balance may be paid in full. Customers with a positive balance in their Budget Pay Plan account at the time of recalculation, or upon termination of the agreement after all charges for services have been paid, will be refunded at the Customer's request. If no request for refund is made, the monthly Budget Pay charges will be equal to the recalculated Budget Pay amount reduced by one-twelfth of the positive balance. Upon the Customer's request, a positive balance for one Budget Pay electric service may be transferred to the balance of another Budget Pay electric service on the account.

Any estimates furnished by the Company with such Budget Pay Plan should not be construed as a guarantee that the total actual charges will not exceed the estimates. The Company, because of rate changes or other requirements, may at any time submit a revised estimate to the Customer and require that the Customer pay the revised monthly Budget Pay installment as a condition to the continuation of the Budget Pay Plan for the Customer.

The Budget Pay amount(s) will be billed on the regular service bill each month. Once established, the Budget Pay Plan will remain in effect from year to year until the Customer notifies the Company not less than 30 days prior to the desired date of cancellation or unless the Customer fails to pay the agreed amounts.

RULE J

CONTINUITY, CURTAILMENT AND INTERRUPTION OF ELECTRIC SERVICE

1, Electric service is inherently subject to occasional interruption, suspension, and fluctuation. The Company will have no liability to its Customers or any other persons for any interruption, suspension, curtailment, or fluctuation in service or for any loss or damage caused thereby if such interruption, suspension, curtailment, or fluctuation results from any of the following:

a. Causes beyond the Company's reasonable control including, but not limited to, fire, flood, drought, winds, acts of the elements, court orders, insurrections or riots, generation failures, lack of sufficient generating capacity, breakdowns of or damage to facilities of the Company or of third parties, acts of God or public enemy, strikes or other labor disputes, civil, military or governmental authority, electrical disturbances originating on or transmitted through electrical systems with which the Company's system is interconnected, and acts or omissions of third parties;

b. Repair, maintenance, improvement, renewal or replacement work on the Company's electrical system, which work in the sole judgment of the Company is necessary or prudent; to the extent practicable work shall be done at such time as will minimize inconvenience to the Customer and, whenever practicable, the Customer shall be given reasonable notice of such work.

c. Actions taken by the Company, which in its sole judgment are necessary or prudent to protect the performance, integrity, reliability or stability of the Company's electrical system or any electrical system with which it is inter-connected, which actions may occur automatically or manually.

2. Load curtailment and interruption carried out in compliance with an order by governmental authority shall follow the Company's plan entitled "Load Curtailment and Interruption Procedure", as filed with and approved by the Commission.

3. The provision of this rule do not affect any persons rights in tort.

RULE K
CUSTOMER'S LOAD AND OPERATIONS

1. Interference with Service. The Company reserves the right to refuse to supply loads of a character that may seriously impair service to any other Customers, or may disconnect existing service if it is seriously impairing service to any other Customers. In the case of pump hoist or elevator motors, welders, furnaces, compressors, and other installations of like character where the use of electricity is intermittent, subject to voltage fluctuations, voltage notching or draws a nonsinusoidal (harmonically distorted) load current, the Company may require the Customer to provide equipment, at the Customer's expense, to reasonably limit such fluctuations.

2. Practices and Requirements of Harmonic Control. Customers are required to comply with the *Practices and Requirements of Harmonic Control in Electric Power Systems* as set forth in the current Institute of Electrical and Electronic Engineers (IEEE) Standard 519. The values indicated by IEEE Standard 519 apply at the point where the Company's equipment interfaces with the Customer's equipment.

3. Change of Load Characteristic. The Customer shall give the Company prior notice before making any significant change in either the amount or electrical character of the Customer's electrical load thereby allowing the Company to determine if any changes are needed in the Company's equipment or distribution system. The Customer may be held liable for damages to the Company's equipment resulting from the Customer's failure to provide said notice of change in electrical load.

4. Protection of Electrical Equipment.

The Customer is solely responsible for the selection, installation, and maintenance of all electrical equipment and wiring (other than the Company's meters and apparatus) on the load side of the Point of Delivery. The Customer should provide adequate protection for equipment, data, operations, work and property under the Customer's control from system disturbances such as (a) high and low voltage, (b) surges, harmonics, and transients in voltage, and (c) overcurrent. For unidirectional and three-phase equipment, the Customer should provide adequate protection from "single phasing conditions", reversal of phase rotation, and phase unbalance.

5. Motor Installations. The Company reserves the right to refuse single phase service to motors larger than 7 ½ horsepower.

   a. Motor Connection. All motor installations greater than 7 ½ horsepower (HP) must be approved by the Company to determine how the motor's connection will affect the Company's system. Changes to Company facilities necessary to address the effects of, but not limited to, flicker, voltage balance, voltage level, or reactive power may be at the Customer's expense.

RULE K
CUSTOMER'S LOAD AND OPERATIONS
(Continuous)

5. Motor Installations (Continued)

b. Allowable Motor Starting Currents. The starting currents (as determined by tests or based on published data by manufacturers) of alternating current motors will not exceed the allowable locked rotor current values shown in the following table, corrections being allowed to compensate for the difference between the voltage supply at the motor terminals and its rated voltage. If the starting current of the motor exceeds the locked rotor current value indicated by the table below, a starter must be used or other means employed to limit the starting current to the locked rotor current value specified, except that such starting equipment may be omitted by written permission of the Company where the absence of such starting equipment will not cause objectionable voltages. Maximum permissible locked rotor current values in the following table apply to a single motor installation. Starters may be omitted on the smaller motors of an installation consisting of more than one motor when their omission will not result in a current in excess of the allowable locked rotor current of the single largest motor of the group.

Allowable Locked Rotor Currents*						
	Single Phase Motors		Three Phase Motors			
	208 Volt	240 Volt	208 Volt	240 Volt	480 Volt	Over 480 Volt
Rated Size HP	Starting Amps Allowed					
7.5	127	110				
10			163	141	71	
15			227	197	99	
20			288	250	125	
25			351	304	152	
30			415	360	180	
40			438	380	190	
50			462	400	200	
60			554	480	240	
75			692	600	300	
Over 75						

*Note: If no value is shown, Company approval of the locked rotor current is required prior to motor installation.

RULE L
Deposits

1. Residential Customers. The Company may require a deposit from a residential customer if: (1) the Customer is unable to establish credit as defined in section 1 of OAR 860-021-0200, (2) the Customer has received electric service from either the Company or another Oregon regulated electric utility within the preceding 24 months and at the time service was terminated owed an account balance that was not paid according to its terms for which a dispute was not registered within 60 days of the date service was terminated, or (3) was previously terminated for theft of service by the Company or any Oregon regulated utility or was otherwise found to have diverted utility service. In either of these two cases, the Company may require a deposit from the Customer equal to one-sixth of the estimated annual billing at the rates then in effect if the calculated deposit amount exceeds $250. The Company's practices relating to deposit payment arrangements for residential customers are governed by OAR 860-021-0205.

2. Commercial and Special Contract Customers (Schedules 7, 9, 19 and Special Contract). The Company may require a deposit from Commercial or Special Contract customers if: (1) the Customer has been disconnected for nonpayment within the last 12 months; (2) the Customer has received more that two 15-day termination notices within the last 12 months; (3) the Customer becomes a debtor in a bankruptcy proceeding; (4) the Customer falsifies information in the application for service; (5) the Customer fails to establish credit satisfactory to the Company; (6) the nature of the Customer's business is speculative or subject to a high rate of failure; (7) the Customer is applying for service with the Company for the first time; (8) the Customer has an outstanding prior service account with the Company that accrued within the last four years and at the time of application for service remains unpaid and not in dispute; or (9) the risk of future loss is evident based on the Customer's current commercial credit rating; or (10) the Customer requests service be provided for a period of less than 90 days. If any of the criteria (1) through (9) are met, the Company may require a deposit not exceeding two times the Customer's estimated monthly billing at the service address if the calculated deposit amount exceeds $250. When a Customer requests service be provided for less than 90 days, a deposit equal to $100 or twice the estimated monthly billing, whichever is greater, may be required.

A new Customer can establish satisfactory credit by presenting to the Company one of the following: (1) a statement from another electric utility showing the Customer's most recent 12-month credit history during which time the Customer had not received any notices of disconnection; (2) a letter of credit from a major financial institution; or (3) a current Dun and Bradstreet report that substantiates the credit reliability of the Customer. Deposits may be paid in two equal installments; the first installment must be paid at the time of the application for service or upon notice from the Company to existing customers, and the second installment must be paid within 30 days.

3. Written Explanation for Denial of Service or Requirement of Deposit. If the Company denies service or requires a cash deposit as a condition of providing or continuing service, then it will provide a written explanation to the Customer stating the reasons why it denies service or requires a deposit. The applicant or Customer will be given an opportunity to rebut those reasons.

4. Interest on Deposits. Interest on deposits held by the Company shall be accrued at the rate established by the Commission specified in OAR 860-021-0210. Interest shall be computed from the time the deposit is made until it is refunded or applied to the Customer's regular bill. Interest will not accrue on a deposit if service is discontinued temporarily at the request of a Customer who leaves the deposit with the Company for future use as a deposit, or if service has been permanently discontinued and the Company has been unsuccessful in its attempt to refund a deposit.

5. Refund of Deposit. Deposits will be refunded with interest or applied to the next monthly bill (at the Customer's option) if the Customer's account is current and the account has not been disconnected for nonpayment nor been issued more than two 5-day disconnection notices during the previous 12 months.

RULE L
Deposits
(Continued)

6. Retention During Dispute. The Company may retain the deposit pending the resolution of a dispute over termination of service. If the deposit is later returned to the Customer, the Company shall pay interest at the annual rates established in OAR 860-021-0210 for the entire period over which the deposit was held.

7. Transfer of Deposit. Deposits shall not be transferred from one Customer to another Customer or between classes of service, except at the Customer's request. When a Customer with a deposit on file transfers service to a new location within the Company's service area, the deposit shall remain with the Customer at the new location.

SCHEDULE 1
RESIDENTIAL SERVICE

AVAILABILITY

Service under this schedule is available at points on the Company's interconnected system within the State of Oregon where existing facilities of adequate capacity and desired phase and voltage are adjacent to the Premises to be served, and additional investment by the Company for new transmission, substation or terminal facilities is not necessary to supply the desired service.

APPLICABILITY

Service under this schedule is applicable to Electric Service required for residential service Customers for general domestic uses, including single phase motors of 7½ horsepower rating or less, subject to the following conditions:

1. When a portion of a dwelling is used regularly for business, professional or other gainful purposes, or when service is supplied in whole or in part for business, professional, or other gainful purposes, the Premises will be classified as non-residential and the appropriate general service schedule will apply. However, if the wiring is so arranged that the service for residential purposes can be metered separately, this schedule will be applied to such service.

2. Whenever the Customer's equipment does not conform to the Company's specifications for service under this schedule, service will be supplied under the appropriate General Service Schedule.

3. This schedule is not applicable to standby service, service for resale, or shared service.

TYPE OF SERVICE

The type of service provided under this schedule is single phase, alternating current at approximately 120 or 240 volts and 60 cycles, supplied through one meter at one Point of Delivery. Upon request by the owner of multi-family dwellings, the Company may provide 120/208 volt service for multi-family dwellings when all equipment is U L approved to operate at 120/208 volts.

WATER HEATING

Electric storage water heating equipment shall conform to specifications of the Underwriters' Laboratories, Inc., and the Company and its installation shall conform to all National, State, and Municipal Codes and may be equipped with one or two heating units. No single heating unit shall exceed 6 kW; and where two heating units are used in a single tank, these units shall be so interlocked that not more than 6 kW can be connected at any one time.

SCHEDULE 1
RESIDENTIAL SERVICE
(Continued)

RESIDENTIAL SPACE HEATING

All space heating equipment to be served by the Company's system shall be single phase equipment approved by Underwriters' Laboratories, Inc., and the equipment and its installation shall conform to all National, State and Municipal Codes and to the following:

Individual resistance-type units for space heating larger than 1,650 watts shall be designed to operate at 240 or 208 volts, and no single unit shall be larger than 6 kW. Heating units of two kW or larger shall be controlled by approved thermostatic devices. When a group of heating units, with a total capacity of more than 6 kW, is to be actuated by a single thermostat, the controlling switch shall be so designed that not more than 6 kW can be switched on or off at any one time. Supplemental resistance-type heaters, that may be used with a heat exchanger, shall comply with the specifications listed above for such units.

SUMMER AND NON-SUMMER SEASONS

The summer season begins on June 1 of each year and ends on August 31 of each year. The non-summer season begins on September 1 of each year and ends on May 31 of each year.

MONTHLY CHARGE

The Monthly Charge is the sum of the Service Charge, the Energy Charge, and the Power Supply Adjustment at the following rates, and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), Schedule 95 (Adjustment for Municipal Exactions), and Schedule 98 (Residential and Small Farm Energy Credit).

	Summer	Non-summer
Service Charge, per month	\$10.00	\$10.00
Energy Charge, per kWh		
0-800 kWh	6.8993¢	6.0303¢
Over 800 kWh	8.9691¢	7.5485¢
Power Supply Adjustment, per kWh	0.4116¢	0.4116¢

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 7
SMALL GENERAL SERVICE

AVAILABILITY

Service under this schedule is available at points on the Company's interconnected system within the State of Oregon where existing facilities of adequate capacity and desired phase and voltage are adjacent to the Premises to be served and additional investment by the Company for transmission, substation, or terminal facilities is not necessary to supply the desired service.

APPLICABILITY

Service under this schedule is applicable to Electric Service supplied to a Customer at one Point of Delivery and measured through one meter. This schedule is applicable to Customers whose metered energy usage is 3,000 kWh, or less, per Billing Period for ten or more Billing Periods during the most recent 12 consecutive Billing Periods. When the Customer's Billing Period is less than 27 days or greater than 36 days, the energy usage will be prorated to 30 days for purposes of determining eligibility under this schedule. Customers whose metered energy usage exceeds 3,000 kWh per Billing Period on an actual or prorated basis three times during the most recent 12 consecutive Billing Periods are not eligible for service under this schedule and will be automatically transferred to the applicable schedule effective with the next Billing Period. New customers may initially be placed on this schedule based on estimated usage.

This schedule is also applicable to non-profit or tax supported ball fields, fairgrounds or rodeo grounds with high demands and intermittent use exceeding 3,000 kWh per month. This schedule is not applicable to standby service, service for resale, or shared service, or to individual or multiple family dwellings, or agricultural irrigation service after October 31, 2005.

TYPE OF SERVICE

The type of service provided under this schedule is single- and/or three-phase, at approximately 60 cycles and at the standard service voltage available at the Premises to be served.

SUMMER NON-SUMMER SEASONS

The summer season begins on June 1 of each year and ends on August 31 of each year. The non-summer season begins on September 1 of each year and ends on May 31 of each year.

MONTHLY CHARGE

The Monthly Charge is the sum of the Service Charge, the Energy Charge, and the Power Supply Adjustment at the following rates, and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), Schedule 95 (Adjustment for Municipal Exactions), and Schedule 98 (Residential and Small Farm Energy Credit).

	Summer	Non-Summer
Service Charge, per month		
Single-Phase Service	$10.00	$10.00
Three-Phase Service	$20.00	$20.00

SCHEDULE 7
SMALL GENERAL SERVICE
(Continued)

MONTHLY CHARGE (Continued)

	Summer	Non-Summer
Energy Charge, per kWh		
0-300 kWh	6.2725¢	6.2725¢
Over 300 kWh	9.1267¢	7.3135¢
Power Supply Adjustment, per kWh	0.4116¢	0.4116¢

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 9
LARGE GENERAL SERVICE

AVAILABILITY

Service under this schedule is available at points on the Company's interconnected system within the State of Oregon where existing facilities of adequate capacity and desired phase and voltage are adjacent to the premises to be served and additional investment by the Company for new transmission, substation, or terminal facilities is not necessary to supply the desired service.

APPLICABILITY

Service under this schedule is applicable to firm Electric Service supplied to a Customer where service at one Point of Delivery and measured through one meter.

This schedule is applicable to Customers whose energy usage exceeds 3,000 kWh per Billing Period for a minimum of three Billing Periods during the most recent 12 consecutive Billing Periods and whose metered Demand per billing Period has not equaled or exceeded 1,000 kW more than twice during the most recent 12 consecutive Billing Periods. When the Customer's Billing Period is less than 27 days or greater than 36 days, the metered energy usage will be prorated to 30 days for purposes of determining eligibility under this schedule. Customers whose metered energy usage does not exceed 3,000 kWh per Billing Period on an actual or prorated basis three or more times during the most recent 12 consecutive Billing Periods or whose metered demand equals or exceeds 1,000 kW per Billing Period three times or more during the most recent 12 consecutive Billing Periods are not eligible for service under this schedule and will be automatically transferred to the applicable schedule effective with the next Billing Period. New customers may initially be placed on this schedule based on estimated usage.

This schedule is not applicable to standby service, service for resale, or shared service, or to individual or multiple family dwellings, or to agricultural irrigation service after October 31, 2005.

TYPE OF SERVICE

The type of service provided under this schedule is single- and/or three-phase, at approximately 60 cycles and at the standard service voltage available at the Premises to be served.

BASIC LOAD CAPACITY

The Basic Load Capacity is the average of the two greatest non-zero monthly Billing Demands established during the 12-month period which includes and ends with the current Billing Period.

BILLING DEMAND

The Billing Demand is the average kW supplied during the 15-consecutive-minute period of maximum use during the Billing Period, adjusted for Power Factor.

ON-PEAK BILLING DEMAND

The On-Peak Billing Demand is the average kW supplied during the 15-minute period of maximum use during the Billing Period for the On-Peak time period.

SCHEDULE 9
LARGE GENERAL SERVICE
(Continued)

FACILITIES BEYOND THE POINT OF DELIVERY

At the option of the Company, transformers and other facilities installed beyond the Point of Delivery to provide Primary or Transmission Service may be owned, operated, and maintained by the Company in consideration of the Customer paying a Facilities Charge to the Company.

Company-owned Facilities Beyond the Point of Delivery will be set forth in a Distribution Facilities Investment Report provided to the Customer. As the company's investment in Facilities Beyond the Point of Delivery changes in order to provide the Customer's service requirements, the Company shall notify the Customer of the additions and/or deletions of facilities by forwarding to the Customer a revised Distribution Facilities Investment Report.

In the event the Customer requests the Company to remove or reinstall or change Company-owned Facilities Beyond the Point of Delivery, the Customer shall pay to the Company the "non-salvable cost" of such removal, reinstallation or change. Non-salvable cost as used herein is comprised of the total original costs of materials, labor and overheads of the facilities, less the difference between the salvable cost of material removed and removal labor cost including appropriate overhead costs.

POWER FACTOR

Where the Customer's Power Factor is less than 90 percent, as determined by measurement under actual load conditions, the Company may adjust the kW measured to determine the Billing Demand by multiplying the measured kW by 90 percent and dividing by the actual Power Factor.

SUMMER AND NON-SUMMER SEASONS

The summer season begins on June 1 of each year and ends on August 31 of each year. The non-summer season begins on September 1 of each year and ends on May 31 of each year.

TIME PERIODS

The time periods are defined as follows. All times are stated in Mountain Time.

Summer Season

On-Peak	1:00 p.m. to 9:00 p.m. Monday through Friday, except holidays
Mid-Peak	7:00 a.m. to 1:00 p.m. and 9:00 p.m. to 11:00 p.m. Monday through Friday, except holidays, and 7:00 a.m. to 11:00 p.m. Saturday and Sunday, except holidays
Off-Peak	11:00 p.m. to 7:00 a.m. Monday through Sunday and all hours on holidays

Non-Summer Season

Mid-Peak	7:00 a.m. to 11:00 p.m., Monday through Saturday, except holidays
Off-Peak	11:00 p.m. to 7:00 a.m. Monday through Saturday and all hours on Sunday and holidays

The holidays observed by the Company are New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day. When New Year's Day, Independence Day, or Christmas Day falls on a Sunday, the Monday immediately following that Sunday will be considered a holiday.

SCHEDULE 9
LARGE GENERAL SERVICE
(Continued)

MONTHLY CHARGE

The Monthly Charge is the sum of the Service Charge, the Energy Charge, and the Power Supply Adjustment at the following rates, and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), Schedule 95 (Adjustment for Municipal Exactions), and Schedule 98 (Residential and Small Farm Energy Credit).

SECONDARY SERVICE	Summer	Non-Summer
Service Charge, per month		
Single Phase Service	$11.50	$11.50
Three Phase Service	$20.25	$20.25
Basic Charge, per kW of Basic Load Capacity	$0.68	$0.68
Demand Charge, per kW of Billing Demand	$5.70	$4.12
Energy Charge, per kWh	4.4290¢	3.8684¢
Power Supply Adjustment, per kWh	0.4116¢	0.4116¢

Facilities Charge
None

PRIMARY SERVICE	Summer	Non-Summer
Service Charge, per month	$215.00	$215.00
Basic Charge, per kW of Basic Load Capacity	$1.04	$1.04
Demand Charge, per kW of Billing Demand	$4.82	$4.45
On-Peak Demand Charge, per kW of On-Peak Billing Demand	$0.69	$0.69
Energy Charge, per kWh		
On-Peak	4.2761	n/a
Mid-Peak	3.8874¢	3.4094¢
Off-Peak	3.6331¢	3.2470¢
Power Supply Adjustment	0.4116¢	0.4116¢

Facilities Charge
The Company's investment in Company-owned Facilities Beyond the Point of Delivery times 1.7 percent.

SCHEDULE 9
LARGE GENERAL SERVICE
(Continued)

TRANSMISSION SERVICE	Summer	Non-Summer
Service Charge, per month	$215.00	$215.00
Basic Charge, per kW of Basic Load Capacity	$0.30	$0.30
Demand Charge, per kW of Billing Demand	$3.59	$3.84
On-Peak Demand Charge, per kW of On-Peak Billing Demand	$0.69	$0.69
Energy Charge, per kWh		
On-Peak	4.2042¢	n/a
Mid-Peak	3.8220¢	3.3536¢
Off-Peak	3.5720¢	3.1939¢
Power Supply Adjustment	0.4116¢	0.4116¢

Facilities Charge
The Company's investment in Company-owned Facilities Beyond the Point of Delivery times 1.7 percent.

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 15
DUSK TO DAWN CUSTOMER LIGHTING

AVAILABILITY

Service under this schedule is available to commercial institutions, industrial plants, and residential Customers presently served from the Company's interconnected system within the State of Oregon where existing overhead secondary distribution facilities of adequate capacity, phase and voltage are presently available adjacent to the Premises to be lighted.

APPLICABILITY

Service under this schedule is applicable to Electric Service provided for the outdoor dusk to dawn lighting of commercial, industrial and residential Customer grounds, yards, driveways and Premises by means of a Company-owned luminary, mounted on an existing Company pole with a support bracket and automatically controlled by a photoelectric relay. At the request of a Customer, but at the sole discretion of the Company, a luminary may be mounted on a Customer-owned support acceptable to the Company. The type and kind of fixtures and supports will be in accordance with the Company's specifications.

CHARACTER OF SERVICE

The facilities required for supplying service, including fixture, lamp, control relay, and support bracket for mounting on an existing Company pole with secondary service or, at the request of a Customer and at the Company's sole discretion, on a Customer-owned support acceptable to the Company, are supplied, installed, owned and maintained by the Company in accordance with the Company's standards and specifications. All necessary repairs and maintenance work, including lamp renewal, will be performed by the Company only during the regularly scheduled working hours of the Company, and the Company shall be allowed 72 hours following notification by the Customer, for replacing any burned out lamps. Lamps are energized each night from 20 minutes after sunset until 20 minutes before sunrise, thereby providing approximately 4,059 hours of Premises lighting per year. The Company retains the right, but not the obligation, to terminate and remove service from a Customer-owned support at any time.

If the Customer requests that the Company install a Company-owned luminary on a Customer-owned support, the Customer through its request, agrees to permit the Company and its representatives reasonable access onto and across the Customer's property for the purposes of installing, maintaining and removing the luminary. In addition, the Customer voluntarily agrees to release the Company (including its directors, officers, employees, agents, parent company, affiliates, successors and assigns) from all liability, loss, claims or actions for injury, death, expenses (including, but not limited to, reasonable attorney fees and court costs) or damage to person or property resulting from the Company's installation, maintenance and removal of the luminary located on a Customer-owned support. The Customer also agrees to indemnify and hold harmless the Company from any liability, claim, loss, action or expense (including, but not limited to, reasonable attorney fees and court costs) asserted against or incurred by the Company for damages arising out of actions or inactions of the Customer and the Customer's employees, agents, representatives or others acting on their behalf.

NEW FACILITIES

Where facilities of the Company are not presently available for a lamp installation which will provide satisfactory lighting service for the Customer's Premises, the Company may install overhead or underground secondary service facilities, including secondary conductor, poles, anchors, etc., a distance not to exceed 300 feet to supply the desired service, all in accordance with the charges specified below.

SCHEDULE 15
DUSK TO DAWN CUSTOMER LIGHTING
(Continued)

MONTHLY CHARGE

The Monthly Charge is the sum of the per Unit Charge and the Power Supply Adjustment at the following charges, and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Exactions).

1. Monthly Per Unit Charge on existing facilities:

AREA LIGHTING

High Pressure Sodium Vapor	Average Lumens	Monthly Base Rate	Power Supply Adjustment
100 Watt	8,550	$9.62	$0.14
200 Watt	19,800	$15.38	$0.28
400 Watt	45,000	$24.37	$0.56

FLOOD LIGHTING

High Pressure Sodium Vapor	Average Lumens	Monthly Base Rate	Power Supply Adjustment
200 Watt	19,800	$18.66	$0.28
400 Watt	45,000	$27.67	$0.56
Metal Halide			
400 Watt	28,800	$30.93	$0.56
1,000 Watt	88,000	$56.22	$1.41

2. For New Facilities Installed Before August 8, 2005. The Monthly Charge for New Facilities installed, prior to August 8, 2005 such as overhead secondary conductor, poles, anchors, etc., shall be 1.75 percent of the estimated installed cost thereof.

3. For New Facilities Installed On or After August 8, 2005: The non-refundable charge for New Facilities to be installed, such as underground service, overhead secondary conductor, poles, anchors, etc., shall be equal to the work order cost.

PAYMENT

The monthly bill for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 19
LARGE POWER SERVICE

AVAILABILITY

Service under this schedule is available at points on the Company's interconnected system within the State of Oregon where existing facilities of adequate capacity and desired phase and voltage are available. If additional distribution facilities are required to supply the desired service, those facilities provided for under Rule H will be provided under the terms and conditions of that rule, To the extent that additional facilities not provided for under Rule H, including transmission and/or substation facilities, are required to provide the requested service, special arrangements will be made in a separate agreement between the Customer and the Company.

APPLICABILITY

Service under this schedule is applicable to and mandatory for Customers who register a metered Demand of 1,000 kW or more per Billing Period for three or more Billing Periods during the most recent 12 consecutive Billing Periods. Customers whose initial usage, based on information provided by the Customer, is expected to be 1,000 kW or more per Billing Period for three or more Billing Periods during 12 consecutive Billing Periods may, at the Customer's request, take service under this schedule prior to meeting the metered demand criterion. This schedule will remain applicable until the Customer fails to register a metered demand of 1,000 kW or more per Billing Period for three or more Billing Periods during the most recent 12 consecutive Billing Periods.

Deliveries at more than one Point of Delivery or more than one voltage will be separately metered and billed. If the aggregate power requirement of a Customer who receives service at one or more Points of Delivery on the same Premises exceeds 20,000 kW, the Customer is ineligible for service under this schedule and is required to make special contract arrangements with the Company.

This schedule is not applicable to service for resale, to shared or irrigation service, to standby or supplemental service, unless the Customer has entered into a Standby Service Agreement or other standby agreement with the Company, or to multi-family dwellings.

TYPE OF SERVICE

The Type of Service provided under this schedule is three-phase at approximately 60 cycles and at the standard service voltage available at the Premises to be served.

BASIC LOAD CAPACITY

The Basic Load Capacity is the average of the two greatest monthly Billing Demands established during the 12-month period which includes and ends with the current Billing Period, but not less than 1,000 kW.

BILLING DEMAND

The Billing Demand is the average kW supplied during the 15-consecutive-minute period of maximum use during the Billing Period, adjusted for Power Factor, but not less than 1,000 kW.

ON-PEAK BILLING DEMAND

The On-Peak Billing Demand is the average kW supplied during the 15-minute period of maximum use during the Billing Period for the On-Peak time period.

SCHEDULE 19
LARGE POWER SERVICE
(Continued)

TIME PERIODS

The time periods are defined as follows. All times are stated in Mountain Time.

Summer Season

On-Peak	1:00 p.m. to 9:00 p.m. Monday through Friday, except holidays
Mid-Peak	7:00 a.m. to 1:00 p.m. and 9:00 p.m. to 11:00 p.m. Monday through Friday, except holidays, and 7:00 a.m. to 11:00 p.m. Saturday and Sunday, except holidays
Off-Peak	11:00 p.m. to 7:00 a.m. Monday through Sunday and all hours on holidays.

Non-Summer Season

Mid-Peak	7:00 a.m. to 11:00 p.m., Monday through Saturday, except holidays
Off-Peak	11:00 p.m. to 7:00 a.m. Monday through Saturday and all hours on Sunday and holidays

The holidays observed by the Company are New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day. When New Year's Day, Independence Day, or Christmas Day falls on a Sunday, the Monday immediately following that Sunday will be considered a holiday.

SUMMER AND NON-SUMMER SEASONS

The summer season begins on June 1 of each year and ends on August 31 of each year. The non-summer season begins on September 1 of each year and ends on May 31 of each year.

FACILITIES BEYOND THE POINT OF DELIVERY

At the option of the Company, transformers and other facilities installed beyond the Point of Delivery to provide Primary or Transmission Service may be owned, operated, and maintained by the Company in consideration of the Customer paying a Facilities Charge to the Company.

Company-owned Facilities Beyond the Point of Delivery will be set forth in a Distribution Facilities Investment Report provided to the Customer. As the Company's investment in Facilities Beyond the Point of Delivery changes in order to provide the Customer's service requirements, the Company shall notify the Customer of the additions and/or deletions of facilities by forwarding to the Customer a revised Distribution Facilities Investment Report.

In the event the Customer requests the Company to remove or reinstall or change Company-owned Facilities Beyond the Point of Delivery, the Customer shall pay to the Company the "non-salvable cost" of such removal, reinstallation or change. Non-salvable cost as used herein is comprised of the total original costs of materials, labor and overheads of the facilities, less the difference between the salvable cost of material removed and removal labor cost including appropriate overhead costs.

SCHEDULE 19
LARGE POWER SERVICE
(Continued)

POWER FACTOR ADJUSTMENT

Where the Customer's Power Factor is less than 90 percent, as determined by measurement under actual load conditions, the Company may adjust the kW measured to determine the Billing Demand by multiplying the measured kW by 90 percent and dividing by the actual Power Factor.

TEMPORARY SUSPENSION

When a Customer has properly invoked Rule G, Temporary Suspension of Demand, the Basic Load Capacity, the Billing Demand, and the On-Peak Billing Demand shall be prorated based on the period of such suspension in accordance with Rule G. In the event the Customer's metered demand is less than 1,000 kW during the period of such suspension, the Basic Load Capacity and Billing Demand will be set equal to 1,000 kW for purposes of determining the Customer's monthly Minimum Charge.

MONTHLY CHARGE

The Monthly Charge is the sum of the Service Charge, the Energy Charge, and the Power Supply Adjustment at the following rates, and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), Schedule 95 (Adjustment for Municipal Exactions), and Schedule 98 (Residential and Small Farm Energy Credit).

SECONDARY SERVICE	Summer	Non-Summer
Service Charge, per month	$215.00	$215.00
Basic Charge, per kW of Basic Load Capacity	$0.68	$0.68
Demand Charge, per kW of Billing Demand	$5.01	$4.12
On-Peak Demand Charge, per kW of On-Peak Billing Demand	$0.69	n/a
Energy Charge, per kWh		
On-Peak	5.4191¢	n/a
Mid-Peak	4.1685¢	4.0061¢
Off-Peak	3.6248¢	3.5769¢
Power Supply Adjustment*, per kWh	0.4116¢	0.4116¢

* A Customer who prepays the Power Supply Adjustment amount pursuant to ORS 757.259(11) shall not be subject to the Power Supply Adjustment rates.

Facilities Charge
None

SCHEDULE 19
LARGE POWER SERVICE
(Continued)

MONTHLY CHARGE (Continued)

PRIMARY SERVICE	Summer	Non-Summer
Service Charge, per month	\$215.00	\$215.00
Basic Charge, per kW of Basic Load Capacity	\$1.04	\$1.04
Demand Charge, per kW of Billing Demand	\$4.82	\$4.45
On-Peak Demand Charge, per kW of On-Peak Billing Demand	\$0.69	n/a
Energy Charge, per kWh		
On-Peak	4.1215¢	n/a
Mid-Peak	3.1704¢	2.9668¢
Off-Peak	2.7569¢	2.6489¢
Power Supply Adjustment*, per kWh	0.4116¢	0.4116¢

* A Customer who prepays the Power Supply Adjustment amount pursuant to ORS 757.259(11) shall not be subject to the Power Supply Adjustment rates.

Facilities Charge
The Company's investment in Company-owned Facilities Beyond the Point of Delivery times 1.7 percent.

SCHEDULE 19
LARGE POWER SERVICE
(Continued)

MONTHLY CHARGE (Continued)

TRANSMISSION SERVICE	Summer	Non-Summer
Service Charge, per month	$215.00	$215.00
Basic Charge, per kW of Basic Load Capacity	$0.30	$0.30
Demand Charge, per kW of Billing Demand	$3.59	$3.84
On-Peak Demand Charge, per kW of On-Peak Demand	$0.69	n/a
Energy Charge, per kWh		
On-Peak	3.8928¢	n/a
Mid-Peak	2.9941¢	2.7946¢
Off-Peak	2.6036¢	2.4952¢
Power Supply Adjustment*, per kWh	0.4116¢	0.4116¢

* A Customer who prepays the Power Supply Adjustment amount pursuant to ORS 757.259(11) shall not be subject to the Power Supply Adjustment rates.

Facilities Charge
The Company's investment in Company-owned Facilities Beyond the Point of Delivery times 1.7 percent.

PAYMENT

The monthly bill for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 23
IRRIGATION PEAK REWARDS
PROGRAM
(OPTIONAL)

PURPOSE

The Irrigation Peak Rewards Program (the Program) is an optional, supplemental service that permits participating agricultural irrigation Customers taking service under Schedule 24 to allow the Company to turn off specific irrigation pumps with the use of one or more Load Control Devices. In exchange for allowing the Company to turn off specified irrigation pumps, participating Customers will receive a financial incentive in the form of a Bill Credit applied to the monthly bills for usage that occurs during the calendar months of June and July for each metered service point (Metered Service Point) enrolled in the Program.

AVAILABILITY

Service under this schedule is available on an optional basis to Customers with a Metered Service Point or Points receiving service under Schedule 24 where the Metered Service Point serves a water pumping or water delivery system used to irrigate agricultural crops or pasturage.

The Company shall have the right to select and reject Program participants at its sole discretion based on criteria the Company considers necessary to ensure the effective operation of the Program. Selection criteria may include, but will not be limited to, Billing Demand, location, pump horsepower, pumping system configuration, or electric system configuration. Past participation does not ensure selection into the Program in future years. Participation may be limited based upon the availability of Program equipment and funding.

Each eligible Customer who chooses to take service under this optional schedule is required to enter into a Uniform Irrigation Peak Rewards Service Application/Agreement (Agreement) with the Company prior to being served under this schedule. The Agreement will grant the Company or its representative permission, on reasonable notice, to enter the Customer's property to install one or more Load Control Devices on the electrical panel servicing the irrigation equipment associated with the Metered Service Points that are enrolled in this Program and to allow the Company or its representative reasonable access to the Load Control Device(s) following the installation. By entering into the Agreement, each Customer also agrees to not increase for the sole purpose of participating in the Program the capacity, horsepower (HP) or size of the irrigation system served by the Company.

PROGRAM DESCRIPTION

Service under this optional, supplementary Program permits the Company to turn off specified irrigation pumps for a limited number of hours during the period of June 15 through July 31 (Program Season). The Company will utilize either dispatchable or timer-based Load Control Devices to turn off specific irrigation pumps during load control events. In limited applications, a select group of eligible Customers will be permitted to manually interrupt electric service to participating irrigation pumps during load control events (See Dispatchable Option 3). In exchange for allowing the Company to interrupt service to specified irrigation pumps, participating Customers will receive a financial incentive in the form of a Bill Credit applied to the monthly bills for usage that occurs during the calendar months of June and July for each Metered Service Point enrolled in the Program.

SCHEDULE 23
IRRIGATION PEAK REWARDS
PROGRAM
(OPTIONAL)
(Continued)

DEFINITIONS

Bill Credit. The Bill Credit is the sum of the Demand Credit and the Energy Credit applied to the Customer's monthly bills for usage that occurs during the calendar months of June and July of each year. This amount may be prorated for the number of days during the months of June and July that fall in the Customer's billing cycle.

Demand Credit. The Demand Credit is a demand-based financial incentive provided in the form of a credit on the monthly bill for the Metered Service Point enrolled in the Program. The monthly Demand Credit is calculated by multiplying the Program kW by the demand-related incentive amount for the Interruption Option selected by the Customer. The Demand Credit will be included on the Customer's monthly bills for usage that occurs during the calendar months of June and July of each year. This amount may be prorated for the number of days during the months of June and July that fall in the Customer's billing cycle.

Energy Credit. The Energy Credit is an energy-based financial incentive provided in the form of a credit on the monthly bill for the Metered Service Point enrolled in the Program. The monthly Energy Credit is calculated by multiplying the Program kWh by the energy-related incentive amount for the Interruption Option selected by the Customer. The Energy Credit will be included on the Customer's monthly bills for usage that occurs during the calendar months of June and July of each year. This amount may be prorated for the number of days during the months of June and July that fall in the Customer's billing cycle.

Load Control Device. Load Control Device refers to any technology, device or system utilized under the Program to enable the Company to initiate the load control event.

Notification of Program Acceptance. An interested Customer must sign and return to the Company an Agreement specifying the Metered Service Point(s) to be included in the Program. If a Customer is selected for participation in the Program, a notification of acceptance into the Program will be mailed to participants, which will include a listing of the Metered Service Point(s) that have been enrolled.

Program kW. The Program kW is the demand amount, as measured at the Customer's meter in kilowatts (kW), that is multiplied by the applicable incentive amount to determine the Demand Credit under each Interruption Option.

Program kWh. The Program kWh is the energy amount, as measured at the Customer's meter in kilowatt-hours (kWh), that is multiplied by the applicable incentive amount to determine the Energy Credit under each Interruption Option.

SCHEDULE 23
IRRIGATION PEAK REWARDS
PROGRAM
(OPTIONAL)
(Continued)

INTERRUPTION OPTIONS

Dispatchable Option

Under the Dispatchable Option, the Company will dispatch remotely service interruptions to specified irrigation pumps any weekday during the Program Season between the hours of 2:00 P.M. and 8:00 P.M. Mountain Daylight Time (MDT), excluding July 4. Service interruptions may last up to 4 hours per day and will not exceed 15 hours per calendar week and 60 hours per Program Season. The Company will provide to participating customers notice of pending service interruption by 4:00 P.M. MDT on the day prior to each load control event. The Company will provide subsequent notice of a pending service interruption 30 minutes notice prior to the start of all load control events and once again prior to the end of all load control events. If prior notice of a pending load control event has been sent, the Company may choose to revoke the load control event and will provide notice to Customers by 1:30 P.M. MDT on the day of the scheduled load control event. The Company will provide notice of a load control event via the following communication technologies: telephone, e-mail and/or text message.

Customers who elect to participate in the Program under a Dispatchable Option may be eligible for one of the following Dispatchable Options:

Option 1. A dispatchable one-way communication Load Control Device will be connected to the electrical panel(s) serving the irrigation pumps associated with the Metered Service Points enrolled in the Program. The Load Control Device utilized under this Dispatchable Option will provide the Company the ability to send a signal that will interrupt or not allow the associated irrigation pumps to operate during dispatched load control events. This option requires that all pumps at the Metered Service Point be controlled.

Under Dispatchable Option 1, the Program kW will be based upon the monthly Billing Demand, as measured in kW, for the associated Billing Period. The Program kWh under this option will be based upon the monthly energy usage, as measured in kWh, for the associated Billing Period.

Customers selecting Dispatchable Option 1 may opt-out of a load control event up to five times per season any time prior to or during a load control event. Each time a customer chooses to opt-out of a load control event a fee of $0.005 per kWh will be assessed based upon the current month's Program kWh. This amount may be prorated for the number of days during the months of June and July that fall in the Customer's billing cycle.

SCHEDULE 23
IRRIGATION PEAK REWARDS
PROGRAM
(OPTIONAL)
(Continued)

INTERRUPTION OPTIONS (Continued)

Option 2. A dispatchable Load Control Device capable of two-way communication will be connected to the electrical panel(s) servicing the irrigation pumps associated with the Metered Service Points enrolled in this Program. The Load Control Device utilized under this Dispatchable Option will provide t he Company and the Customer remote control and monitoring of the associated irrigation pumps. Under this option, the Company will use this technology to send a signal that will interrupt or not allow the irrigation pumps to operate during dispatched load control events. This option requires that all pumps at the Metered Service Point be controlled.

Under Dispatchable Option 2, the Program kW will be based upon the monthly Billing Demand, as measured in kW, for the associated Billing Period. The Program kWh under this option will be based upon the monthly energy usage, as measured in kWh, for the associated Billing Period.

Customer selecting Dispatchable Option 2 may opt-out of a load control event up to five times per season any time prior to or during a load control event. Each time a customer chooses to opt-out of a load control event a fee of $0.005 per kWh will be assessed based upon the current month's Program kWh. This amount may be prorated for the number of days during the months of June and July that fall in the Customer's billing cycle.

Option 3. Metered Service Points with interval metering having more than one pump and at least 1,000 cumulative HP are eligible for Dispatchable Option 3. Under this Dispatchable Option, eligible Customers can choose to either 1) have service interrupted using a dispatchable two-way communication Load Control Device, as in Dispatchable Option 2, or 2) manually interrupt electric service to participating irrigation pumps during load control events. This option provides Customers with the flexibility to choose which irrigation pumps will be interrupted during each dispatched load control event.

Under Dispatchable Option 3, the Program kW will be based upon the monthly Billing Demand minus the average demand, as measured in kW over 15 minute intervals, during each load control event initiated during a Billing Period. The Program kWh under this option will be based upon a calculated value, as measured in kWh. The Program kWh will be calculated separately for each Billing Period by multiplying the monthly Program kW by the ratio of the monthly energy usage to the Billing Demand for the associated Billing Period.

Timer Option

Under the Timer Option, the Company or its representative will install a timer-based Load Control Device on the Customer's electrical panel controlling the irrigation pumps at the Metered Service Point enrolled in the Program. The Company or its representative will set the timer or timers to interrupt specified irrigation pumps on a designated weekday or designated weekdays selected by the Customer. The Company will set each timer to interrupt service during the weekday hours of 4:00 P.M

SCHEDULE 23
IRRIGATION PEAK REWARDS
PROGRAM
(OPTIONAL)
(Continued)

INTERRUPTION OPTIONS (Continued)

to 8:00 P.M. MDT. Each Metered Service Point's timer will be set to interrupt service on one, two, or three regularly scheduled weekdays per week for each week during the Program Season. The Company retains the sole right to select the load reduction weekday(s) for each Metered Service Point.

Changes to the Interruption Schedule. A Customer who elects to reduce the number of days of weekly interruption of a Metered Service Point on or after June 15 of each calendar year shall pay the Company the sum of $100.00, which sum will be included on the Customer's monthly bill following the implementation of the requested change. The Customer's Bill Credit shall be prorated based upon the number of days in that month the Customer participated under each interruption schedule. The Company will not accept any requests to increase the number of days of weekly interruption on or after June 15 of each calendar year.

INCENTIVE STRUCTURE

Dispatchable Interruption Option		
Dispatchable Option	Demand Credit ($ per Program kW)	Energy Credit ($ per Program kWh)
1	$4.65	$0.031
2	$4.65	$0.031
3	$4.65	$0.031
Timer Interruption Option		
Timer Option	Demand Credit ($ per Program kW)	Energy Credit ($ per Program kWh)
One Weekday	$3.15	$0.000
Two Weekdays	$4.65	$0.002
Three Weekdays	$4.65	$0.007

INSTALLATION FEES

An Installation Fee may be applicable depending upon the size, as measured in horsepower, of the irrigation system associated with a participating Metered Service Point. The purpose of the Installation Fee is to offset a portion of the installation costs associated with Metered Service Points having smaller load reduction capabilities. The Installation Fee is non-refundable except when a Customer elects for Early Termination of the Program. An Installation Fee will apply according to the following table:

SCHEDULE 23
IRRIGATION PEAK REWARDS
PROGRAM
(OPTIONAL)
(Continued)

INSTALLATION FEES (Continued)

Horsepower (HP)	Dispatchable Option			Timer Option
	1	2	3 *	
Less than 30 HP	$500	$1,000	N/A	$500
From 30 to 49 HP	$0	$500	N/A	$350
From 50 to 74 HP	$0	$0	N/A	$350
From 75 to 99 HP	$0	$0	N/A	$250
Greater than 99 HP	$0	$0	N/A	$0

Note: (*) An installation Fee will not be assessed under Dispatchable Option 3.

TERM OF AGREEMENT AND TERMINATION

The term of the Agreement, as it applies to each Metered Service Point accepted for participation, shall commence on the date the Agreement is signed by both the Customer and the Company and shall automatically renew on March 15 of each calendar year unless notice of termination is given by either party to the other prior to the annual renewal date or unless otherwise terminated as follows:

1. A Customer may terminate the participation of a Metered Service Point without penalty by notifying the Company or its representative before the Load Control Device(s) has been installed on the Metered Service Point (Early Termination).

2. A Customer who terminates the participation of a Metered Service Point anytime between June 15 and July 31 of each calendar year and who does not satisfy the provisions of item 1 above, shall pay the Company a Termination Fee, which sum will be included on the Customer's monthly bill following termination of participation. The Customer's Bill Credit shall be prorated for the number of days in that month the Customer satisfactorily participated in the Program. In the first year that a Metered Service Point becomes enrolled in the Program, a Termination Fee will also be assessed whenever a Customer does not satisfy the provisions of item 1 and requests to terminate participation of the newly enrolled Metered Service Point anytime prior to July 31. Upon terminating participation of a Metered Service Point under the provisions of item 2, the Customer may not re-enroll the Metered Service Point into the Program until the following calendar year.

Termination Fees:

Dispatchable Option $500.00 per Metered Service Point terminated under item 2
Timer Option $100.00 per Metered Service Point terminated under item 2

3. If there is evidence of alteration, tampering, or otherwise interfering with the Company's ability to initiate a load control event at a Metered Service Point, the Agreement as it applies to that Metered Service Point will be automatically terminated. In addition, the Customer will be subject to each of the following:

SCHEDULE 23
IRRIGATION PEAK REWARDS
PROGRAM
(OPTIONAL)
(Continued)

TERM OF AGREEMENT AND TERMINATION (Continued)

a. The Customer will be required to reimburse the Company for the cost of replacement or repair of the Load Control Device(s), including labor and other related costs.

b. An applicable Termination Fee, as provided under item 2, will be applied to the Customer's monthly bill following the termination of participation.

c. The Company will reverse any and all Demand Credits and/or Energy Credits applied to the Customer's monthly bill(s) for the Metered Service Point as a result of the Customer's participation in the Program during the current year.

Note: A service disconnection for any reason does not terminate the Agreement.

SPECIAL CONDITIONS

The provisions of this schedule do not apply for any time period that the Company utilizes a Load Control Device installed under this Program to interrupt the Customer's load for a system emergency or any other time that a Customer's service is interrupted by events outside the control of the Company. The provisions of this schedule will not affect the calculation or rate of the regular Service, Energy or Demand Charges associated with a Customer's standard service schedule.

Mass memory meters may be installed on a select number of Metered Service Points for Program monitoring and evaluation purposes. The sample of Metered Service Points selected for monitoring and evaluation will be chosen at the Company's sole discretion.

SCHEDULE 23
IRRIGATION PEAK REWARDS
PROGRAM
(OPTIONAL)
(Continued)

Uniform Irrigation Peak Rewards Service
Application/Agreement

THIS AGREEMENT Made this ____ day of ________________________________, ______ between ____ hereinafter called Customer, whose billing address is ____, and IDAHO POWER COMPANY, a corporation with its principal office located at 1221 West Idaho Street, Boise, Idaho, hereinafter called Company. This Agreement shall automatically renew on March 15 of each calendar year unless notice of termination is given by either party to the other prior to the annual renewal date. This Agreement is for the Metered Service Point(s) identified on the attached worksheet (Worksheet):

The Customer designates the following person as the Customer's authorized contact:

Authorized Contact: ____
Phone: ____________________________________ Cell Phone: ______________________________
Fax: ____
Email: ____

NOW, THEREFORE, The Parties agree as follows:

1. The Uniform Irrigation Peak Rewards Service Application/Agreement must be signed by the Customer and the Customer must be the person who is responsible for paying bills for retail electric service provided by the Company at the Metered Service Point(s) identified on the Worksheet.

2. The Customer understands that the information concerning the Metered Service Point(s) on the Worksheet is based on the best information currently available to the Company. The Bill Credit amounts are estimates based on the previous year's billing history for the Metered Service Point(s) specified on the Worksheet. Customers without sufficient billing history will be provided an estimated Bill Credit based on the stated cumulative horsepower at the Metered Service Point. The Bill Credit estimates are provided for illustration purposes. The Customer agrees to specify which Metered Service Point(s) listed on the Worksheet the Customer wishes to enroll in the Program and the Interruption Option selected for each specified Metered Service Point.

3. From time to time during the term of this Agreement and with prior reasonable notice from the Company, the Customer shall permit the Company or its representative to enter the Customer's property on which the enrolled Metered Service Point(s) are located to permit the Company or its representative to install, service, maintain and/or remove Load Control Device(s) on the electrical panel that services the Customer's irrigation pumps. The Load Control Device(s) may remain in place on the Customer's property upon termination of the Agreement unless the Customer specifically requests removal.

SCHEDULE 23
IRRIGATION PEAK REWARDS
PROGRAM
(OPTIONAL)
(Continued)

Uniform Irrigation Peak Rewards Service
Application/Agreement
(Continued)

4. The Customer understands and acknowledges that by participating in the Program, the Company shall, at its sole discretion, have the ability to interrupt the specified irrigation pumps at the Metered Service Point(s) enrolled in the Program according to the provisions of the Interruption Option selected. The Company retains the sole right to determine the criteria under which a load control event is scheduled for each Metered Service Point. The Customer also understands and acknowledges that if a Metered Service Point provides electricity to more than one irrigation pump, each pump will be scheduled for service interruption simultaneously, excluding Metered Service Points participating in the Program under Dispatchable Option 3.

5. The Customer may be required to pay an Installation Fee when a Load Control Device is installed on an eligible Metered Service Point providing electric service to irrigation pumps with less than 100 cumulative horsepower. The Installation Fee is non-refundable except when a Customer elects for Early Termination of the Program.

6. For the Customer's satisfactory participation in the Program, the Company agrees to pay the Customer the Demand Credit and/or Energy Credit corresponding to the Interruption Option selected by the Customer. The Bill Credit included on the Worksheet is based upon the billing history for the Metered Service Point(s) specified on the Worksheet, for the months of June, and July of the prior year. The Bill Credit will be paid in the form of a credit on the Customer's monthly bill. The Demand Credit may be prorated for the months of June and July depending on the Customer's billing cycle.

7. If the Customer terminates this Agreement anytime between June 15 and July 31 of the current calendar year while the Metered Service Point(s) are still connected for service and has not elected Early Termination of the Program, the Customer agrees to pay the Company the applicable Termination Fee, which sum will be included on the Customer's monthly bill. The Customer's Bill Credit for the month of termination shall be prorated for the number of days in that month that the Customer is a participant in good standing in the Program. In the first year that a Metered Service Point becomes enrolled in the Program, a Termination Fee will also be assessed whenever the Customer does not elect for Early Termination and requests to terminate the participation of the newly enrolled Metered Service Point anytime prior to July 31. Upon terminating participation of a Metered Service the Customer may not re-enroll that Metered Service Point into the Program until the following calendar year.

8. Under the Timer Option, whenever the Customer elects to change Options to reduce the number of days of weekly interruption of a Metered Service Point on or after June 15 of each calendar year, the Customer shall pay the Company the sum of $100.00, which sum will be included on the Customer's monthly bill following the implementation of the requested change. The Customer's Bill Credit shall be prorated based upon the number of days in that month the Customer participated under each interruption schedule. The Company will not accept any requests to increase the number of days of weekly interruption on or after June 15 of each calendar year.

SCHEDULE 23
IRRIGATION PEAK REWARDS
PROGRAM
(OPTIONAL)
(Continued)

Uniform Irrigation Peak Rewards Service
Application/Agreement
(Continued)

9. If there is evidence of alteration, tampering, or otherwise interfering with the Company's ability to initiate a load control event at a Metered Service Point(s), the Agreement as it applies to that Metered Service Point will be automatically terminated. The Customer will also be required to reimburse the Company for all costs of replacement or repair of the Load Control Device(s), including labor and other related costs, pay the Company the applicable Termination Fee which sum will be included on the Customer's monthly bill and the Company will reverse any Demand Credits applied to the Customer's monthly bill(s) for the Metered Service Point as a result of the Customer's participation in the Program during the current year.

10. The Company's Schedule 23, any revisions to that schedule and/or any successor schedule are to be considered part of this Agreement.

11. This Agreement and the rates, terms and conditions of service set forth or incorporated herein and the respective rights and obligations of the Parties hereunder shall be subject to valid laws and to the regulatory authority and orders, rules and regulations of the Oregon Public Utility Commission and such other administrative bodies having jurisdiction.

12. Nothing herein shall be construed as limiting the Idaho Public Utilities Commission from changing any terms, rates, charges, classification of service or any rules, regulations or conditions relating to service under this Agreement, or construed as affecting the right of the Company or the Customer to unilaterally make application to the Commission for any such change.

13. In any action at law or equity under this Agreement and upon which judgment is rendered, the prevailing Party, as part of such judgment, shall be entitled to recover all costs, including reasonable attorneys fees, incurred on account of such action.

14. The Company retains the sole right to select and reject the participants to receive service under Schedule 23. The Company retains the sole right for its employees and its representatives to install or not install Load Control Devices on the Customer's electrical panel at the time of installation depending on, but not limited to, safety, reliability, or other issues that may not be in the best interest of the Company, its employees or its representatives.

15. Under no circumstances shall the Company or any subsidiary, affiliates or parent Company be held liable to the Customer or any other party for damages or for any loss, whether direct, indirect, consequential, incidental, punitive or exemplary resulting from the Program or from the Customer's participation in the Program. The Customer assumes all liability and agrees to indemnify and hold harmless the Company and its subsidiaries, affiliates and parent company for personal injury, including death, and for property damage caused by the Customer's decision to participate in the Program and to reduce loads.

SCHEDULE 23
IRRIGATION PEAK REWARDS
PROGRAM
(OPTIONAL)
(Continued)

Uniform Irrigation Peak Rewards Service
Application/Agreement
(Continued)

The Company makes no warranty of merchantability or fitness for a particular purpose with respect to the Load Control Device(s) and any and all implied warranties are disclaimed.

(Appropriate Signatures)

SCHEDULE 24
AGRICULTURAL IRRIGATION SERVICE

AVAILABILITY

Service under this schedule is available at points on the Company's interconnected system within the State of Oregon for loads up to 25,000 kW where existing facilities of adequate capacity and desired phase and voltage are adjacent to the Premises to be served, and additional investment by the Company for new transmission, substation or terminal facilities is not necessary to supply the desired service. If the aggregate power requirement of a Customer who receives service at one or more Points of Delivery on the same Premises exceeds 25,000 kW, special contract arrangements will be required.

APPLICABILITY

Service under this schedule is applicable to power and energy supplied to agricultural use customers operating water pumping or water delivery systems used to irrigate agricultural crops or pasturage at one Point of Delivery and through one meter. Water pumping or water delivery systems include, but are not limited to, irrigation pumps, pivots, fertilizer pumps, drainage pumps, linears, and wheel lines.

TYPE OF SERVICE

The type of service provided under this schedule is single- and/or three-phase, alternating current, at approximately 60 cycles and at the standard voltage available at the Premises to be served.

SERVICE CONNECTION AND DISCONNECTION

The Company will routinely keep service connected throughout the calendar year unless the Customer requests service be disconnected. Customer requested service disconnections will be made at no charge during the Company's normal business hours. The Company's termination practices as specified under Rule F will continue to apply with the exception that service terminations will not be made during the Irrigation Season.

Service Connection Charge. A Service Connection Charge as specified in Schedule 66 will be assessed when service is reconnected.

Service Establishment Charge. A Service Establishment Charge as specified in Schedule 66 will be assessed when service that is currently energized at the Point of Delivery is established for the Customer.

SEASONAL DEFINITION

The Irrigation Season will begin with the Customer's meter reading for the May Billing Period and end with the Customer's meter reading for the September Billing Period. The beginning cycles of a Billing Period may actually be based on meter readings taken not more than 7 days prior to the start of the corresponding calendar month.

SCHEDULE 24
AGRICULTURAL IRRIGATION SERVICE
(Continued)

BILLING DEMAND

The Billing Demand is the average kW supplied during the 15-consecutive-minute period of maximum use during the Billing Period, adjusted for Power Factor; PROVIDED That at the Company's option the Billing Demand of a single motor installation of 5 horsepower and less may be equal to the number of horsepower but not less than 1 kW. Metered power demands in kW which exceed 130 percent of the connected horsepower served through one Point of Delivery will not be used for billing purposes unless and until verified by field test in the presence of the Customer to be the result of normal pumping operations. If a demand in excess of 130 percent of the connected horsepower is the result of abnormal conditions existing on the Company's interconnected system or the Customer's system, including accidental equipment failure or electrical supply interruption which results in the temporary separation of the Company's and the Customer's system, the Billing Demand shall be 130 percent of the connected horsepower. Customers may appeal the Company's billing decision to the Oregon Public Utility Commission in cases of dispute.

FACILITIES BEYOND THE POINT OF DELIVERY

At the option of the Company, transformers and other facilities installed beyond the Point of Delivery to provide Transmission Service may be owned, operated, and maintained by the Company in consideration of the Customer paying a Facilities Charge to the Company.

Company-owned Facilities Beyond the Point of Delivery will be set forth in a Distribution Facilities Investment Report provided to the Customer. As the Company's investment in Facilities Beyond the Point of Delivery changes in order to provide the Customer's service requirements, the Company shall notify the Customer of the additions and/or deletions of facilities by forwarding to the Customer a revised Distribution Facilities Investment Report.

In the event the Customer requests the Company to remove or reinstall or change Company-owned Facilities Beyond the Point of Delivery, the Customer shall pay to the Company the "non-salvable cost" of such removal, reinstallation or change. Non-salvable cost as used herein is comprised of the total original costs of materials, labor and overheads of the facilities, less the difference between the salvable cost of material removed and removal labor cost including appropriate overhead costs.

POWER FACTOR ADJUSTMENT

Where the Customer's Power Factor is less than 90 percent, as determined by measurement under actual load conditions, the Company may adjust the kW measured to determine the Billing Demand by multiplying the measured kW by 90 percent and dividing by the actual Power Factor.

SCHEDULE 24
AGRICULTURAL IRRIGATION SERVICE
(Continued)

MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), Schedule 95 (Adjustment for Municipal Exactions), and Schedule 98 (Residential and Small Farm Energy Credit).

SECONDARY SERVICE	In-Season	Out-of-Season
Service Charge, per month	$15.00	$3.00
Demand Charge, per kW of Billing Demand	$7.20	$0.00
Energy Charge		
In Season		
First 164 kWh per kW of Demand	5.2513¢	n.a.
All Other kWh	5.0977¢	n.a.
Out-of-Season		
All kWh	n.a.	5.5152¢
Power Supply Adjustment, per kWh	0.4116¢	0.4116¢

Facilities Charge
None

TRANSMISSION SERVICE	In-Season	Out-of-Season
Service Charge, per month	$128.00	$3.00
Demand Charge, per kW of Billing Demand	$6.80	$0.00
Energy Charge		
In Season		
First 164 kWh per kW of Demand	5.0453¢	n.a.
All Other kWh	4.8977¢	n.a.
Out-of-Season		
All kWh	n.a.	5.2989¢
Power Supply Adjustment, per kWh	0.4116¢	0.4116¢

Facilities Charge
The Company's investment in Company-owned Facilities Beyond the Point of Delivery times 1.7 percent.

SCHEDULE 24
AGRICULTURAL IRRIGATION SERVICE
(Continued)

PAYMENT

All monthly billings for Electric Service supplied hereunder are payable upon receipt, and become past due 15 days from the date on which rendered.

Deposit. A deposit payment for irrigation Customers is required under the following conditions:

1. Existing Customers.

a. Tier 1 Deposit. Customers who have two or more reminder notices for nonpayment of Electric Service during a 12-month period, or who have had service terminated for non-payment, or were required to pay a Tier 2 Deposit for the previous Irrigation Season, will be required to pay a Tier 1 Deposit, or provide a guarantee of payment from a bank or financial institution acceptable to the Company. A Tier 1 Deposit does not apply to Customers who have an outstanding balance on December 31 of over $1,000.00 (See Tier 2 Deposit). A reminder notice is issued approximately 45 days after the bill issue date if the balance owing for Electric Service totals $100 or more. The deposit for a specific installation is computed as follows:

(1) Monthly Billing Demand is determined by multiplying 80 percent times the connected horsepower.

(2) Monthly Energy (billing kWh) is determined by multiplying 50 percent times 720 hours times the Monthly Billing Demand.

(3) The Monthly Billing Demand and the Monthly Energy are multiplied by the current In-Season rates and added to the Irrigation In-Season Service Charge to determine the estimated monthly bill.

(4) The estimated monthly bill is multiplied by a factor of one and one-half (1.5).

b. Tier 2 Deposit. Customers who have an outstanding balance greater than $1,000.00 on December 31 will be required to pay a Tier 2 Deposit. A Tier 2 Deposit will also be required from Customers who have had an unpaid past due balance greater than $1,000 on December 31 during any of the previous 4 years and who have not subsequently had active service. A Tier 2 Deposit may be satisfied by a guarantee of payment from a bank or financial institution acceptable to the Company. The deposit for a specific installation is computed as follows:

(1) Monthly Billing Demand is determined by multiplying 80 percent times the connected horsepower.

(2) Monthly Energy (billing kWh) is determined by multiplying 50 percent times 720 hours times the Monthly Billing Demand.

(3) The Monthly Billing Demand and the Monthly Energy are multiplied by the current In-Season rates and added to the Irrigation In-Season Service Charge to determine the estimated monthly bill.

(4) The estimated monthly bill is multiplied by a factor of four (4)

SCHEDULE 24
AGRICULTURAL IRRIGATION SERVICE
(Continued)

2. New Customer. A deposit may be required for a new Customer at the Company's discretion. The deposit for a specific installation will be computed using the same methodology as outlined for existing Customers requiring a Tier 1 Deposit.

3. Bankruptcy or Receivership. An adequate assurance of payment as agreed to by the Company or as may be ordered by a court of competent jurisdiction or the OPUC, shall be required from any Customer for whom an order for relief has been entered under the federal bankruptcy laws, or for whom a receiver has been appointed in a court proceeding. The maximum amount required for each season shall not exceed a payment equal to a deposit. For each irrigation season, an adequate assurance of payment shall be required as agreed to by the Company, or as may be ordered by a court of competent jurisdiction, or the OPUC. This requirement shall continue from the date of the order for relief in bankruptcy, or the court appointing a receiver, until the debtor's discharge in bankruptcy or the dismissal of the court proceeding. A Customer who has been discharged from bankruptcy or whose receivership proceeding has been terminated will be required to pay a Tier 2 Deposit at the start of the following season to the extent required by the payment provisions listed under "Payment" section 1(b) above.

APPLICATION OF DEPOSIT/INTEREST

Interest will be computed by the Company on irrigation deposits required under this schedule at the annual percentage rate determined by the Commission under Oregon Administrative Rules 860–021–0210. The irrigation deposit, with accrued interest, will be applied to the Customer's account as follows:

Tier 1 Deposits/Interest. All Tier 1 Deposits plus accrued interest will be applied to the Customer's account upon date of disconnection or at the time the Customer's September bill is prepared, whichever is earlier.

Tier 2 Deposits/Interest. A portion of the Tier 2 Deposit plus accrued interest equal to the monthly billing amount will be applied to the Customer's account each month until the Tier 2 Deposit amount plus accrued interest is depleted. Any Tier 2 Deposit amount and/or accrued interest remaining at the date of service disconnection or at the time of the Customer's September billing, whichever is earlier, will be applied to the Customer's account

Each irrigation Customer, upon making a deposit payment, will be required to furnish to the Company an IRS Tax Identification or Social Security number for the Company's IRS reporting requirements.

If a Customer tenders to the Company an irrigation deposit which has not been requested or demanded by the Company, the Company may refuse to accept and retain such deposit. If, however, the Company accepts or retains the deposit, the Company will apply the deposit to the Customer's account and no interest will be paid.

SCHEDULE 27
IRRIGATION EFFICIENCY
REWARDS PROGRAM

AVAILABILITY

Service under this schedule is available to agricultural irrigation customers taking service under Schedule 24 throughout the Company's service area within the State of Oregon and who meet the qualifications of the Irrigation Efficiency Rewards Program.

APPLICABILITY

Service under this schedule is applicable to energy efficiency projects related to existing or new agricultural irrigation systems that meet the requirements of the Irrigation Efficiency Rewards Program.

PROGRAM DESCRIPTION

The Irrigation Efficiency Rewards Program is an incentive based program designed to help cover a portion of the costs of designing and installing energy efficiency features into a new or existing irrigation system. The primary goal of this program is to encourage agricultural irrigation Customers to install or modify irrigation systems in order to reduce peak demand and energy consumption in their operations. The Irrigation Efficiency Rewards Program also encourages and assists agricultural irrigation Customers to use electricity in an economically efficient manner through education and information, expert energy audits, annual workshops, energy efficiency demonstration projects, and expert system analysis by a Company agricultural representative.

INCENTIVE OPTIONS

The two incentive options available to Customers under the Irrigation Efficiency Rewards Program are the Custom Option and the Menu Option. Under the Custom Option, Customers who wish to receive a financial incentive are required to submit an energy efficiency project proposal for review by the Company to determine project viability and cost-effectiveness. Upon approval by the Company, a financial incentive is paid to the Customer on the basis of the estimated annual energy savings or demand reduction that is expected to result from the project. Under the Menu Option, Customers select from a predetermined list of approved energy efficient equipment rebuild or repair measures. Customers selecting the Menu Option receive a financial incentive paid on the basis of the number of equipment units installed, replaced or repaired as documented by a copy of the purchase invoice provided to the Company by the Customer. The incentive amounts available under the Menu Option are limited to 100% of the purchase invoice cost except where noted.

SCHEDULE 27
IRRIGATION EFFICIENCY
REWARDS PROGRAM
(Continued)

Custom Option

Project viability will be determined by the Company. New and existing system project proposals submitted to the Company for consideration will be evaluated for program eligibility based upon the following information supplied by the Customer:

1. An itemized cost estimate from the equipment dealer, which must include the make, model and equipment specifications for both new and existing irrigation systems.

2. An irrigation system drawing that includes:

   a. Location of the pumps and water sources
   b. Mainline sizes, lengths, types and locations
   c. Elevations
   d. Number of irrigated acres

3. A pump curve detailing the number of stages and impeller diameter.

4. A topographical map of the irrigation system area.

5. An aerial map of the irrigated acres.

Applicable Projects		
Measure Type	Incentive	Eligibility Requirements
Existing system project	$0.25 per annual kilowatt-hour saved (kWh/yr) or $450.00 per kilowatt of demand reduction (kW)	Existing system project eligibility will be determined based upon the energy and demand savings estimated by the Company. The incentive for existing systems is limited to a cap of 75% of the total project cost.
New system project	$0.25 per annual kilowatt-hour saved (kWh/yr)	New system project eligibility will be determined based upon the energy savings estimated by the Company. The incentive for new systems is limited to a cap of 10% of the total project cost.

SCHEDULE 27
IRRIGATION EFFICIENCY
REWARDS PROGRAM
(Continued)

Menu Option

Applicable Measures		
Measure Type	Incentive	Eligibility Requirements
New flow control nozzles	$1.50 per nozzle	New flow control nozzles must replace existing brass nozzles or worn out flow control nozzles of the same flow rate or less to be eligible for an incentive under this option. The incentive amount is limited to two nozzles per sprinkled acre.
New nozzles	$0.25 per nozzle	New nozzles must replace worn out nozzles of the same flow rate or less to be eligible for an incentive under this option. The incentive amount is limited to two nozzles per sprinkled acre.
Rebuilt or new brass impact sprinklers	$2.75 per sprinkler* (see restriction)	New or rebuilt impact sprinklers replacing existing sprinklers on hand-lines, wheel-lines or solid type systems are eligible for an incentive under this option. Impact sprinklers must be rebuilt to like-new condition and are subject to verification by the Company. The incentive amount is limited to two heads per sprinkled acre.
New rotating type or low-pressure pivot sprinkler heads	$2.75 per sprinkler	New sprinkler heads must have an equal or lower flow rate than the replaced sprinkler heads to be eligible for an incentive under this option.
New low-pressure regulators	$5.00 per regulator	New low-pressure regulators with equal or lower pressure design than the replaced regulators are eligible for an incentive under this option.
New drains, riser caps and gaskets for hand lines, wheel-lines or portable mainlines	$1.00 per measure type* (see restriction)	Replacement of drains, riser caps and gaskets for components of existing hand-lines, wheel-lines or portable mainlines are eligible for an incentive under this option. The incentive amount is limited to two per measure type per sprinkled acre.
New wheel-line hubs	$12.00 per hub	Only Thunderbird brand wheel-lines are eligible for an incentive under this option.
New gooseneck with drop tube or boomback	$1.00 per measure type	New goosenecks with drop tubes or boombacks must be installed on an existing pivot to be eligible for an incentive under this option.
Cut and pipe press or weld repair	$8.00 per joint	Repaired leaking hand-lines, wheel-lines and portable mainlines are eligible for an incentive under this option.
* Incentive Restriction: Measure types indicated with a (*) are eligible for a maximum incentive amount equal to either the lesser of the stated incentive amount or 50% of the purchase invoice cost for each successfully installed measure.		

SCHEDULE 27
IRRIGATION EFFICIENCY
REWARDS PROGRAM
(Continued)

Menu Option (Continued)

Applicable Measures		
Measure Type	Incentive	Eligibility Requirements
New or rebuilt wheel-line levelers	$0.75 per leveler	New or rebuilt levelers replacing existing levelers are eligible for an incentive under this option. Levelers must be rebuilt to like-new condition and are subject to verification by the Company.
New center pivot base boot gasket	$125.00 per gasket	A new center pivot base boot gasket must replace an existing center pivot base boot gasket to be eligible for an incentive under this option. The incentive amount may exceed 100% of the purchase invoice cost whenever the installation is completed by the Customer.
* Incentive Restriction: Measure types indicated with a (*) are eligible for a maximum incentive amount equal to either the lesser of the stated incentive amount or 50% of the purchase invoice cost for each successfully installed measure.		

SCHEDULE 40
UNMETERED GENERAL SERVICE

AVAILABILITY

Service under this schedule is available at points on the Company's interconnected system within the State of Oregon where existing secondary distribution facilities of adequate capacity, phase and voltage are available adjacent to the Customer's Premises and the only investment required by the Company is an overhead service drop.

APPLICABILITY

Service under this schedule applies to Electric Service for the Customer's single- or multiple-unit loads up to 1,800 watts per unit where the size of the load and period of operation are fixed and, as a result, actual usage can be accurately determined. Service may include, but is not limited to, street and highway lighting, security lighting, telephone booths and CATV power supplies which serve line amplifiers. Equipment or loads constructed or operated in such a way as to allow for the potential or actual variation in energy use are not eligible for service under this schedule. Facilities to supply service under this schedule shall be installed so that service cannot be extended to the Customer's loads served under other schedules. Service under this schedule is not applicable to shared or temporary service, or to the Customer's loads on Premises which have metered service.

SPECIAL TERMS AND CONDITIONS

The Customer shall pay for all Company investment, except the overhead service drop, required to provide service requested by the Customer. The Customer is responsible for installing, owning and maintaining all equipment, including necessary underground circuitry and related facilities to connect with the Company's facilities at the Company designated Point of Delivery. If the Customer's equipment is not properly maintained, service to the specific equipment will be terminated.

Energy used by CATV power supplies which serve line amplifiers will be determined by the power supply manufacturer's nameplate input rating assuming continuous operation.

The Customer is responsible for notifying the Company of any changes or additions to the equipment or loads being served under this schedule. Failure to notify the Company of such changes or additions will result in the termination of service under this schedule and the requirement that service be provided under one of the Company's metered service schedules.

If the Customer modifies existing equipment being served under this schedule in a way that allows for the potential or actual variation in energy usage or installs additional equipment that allows for the potential or actual variation in energy usage, service under this schedule will be terminated and the Customer will be required to receive service under one of the Company's metered service schedules.

With Company approval, municipalities or agencies of federal, state, or county governments may install equipment that allows for the potential intermittent variation in energy usage at authorized Points of Delivery. Under these circumstances, the Customer's bill will include fixed units of the Intermittent Usage Charge in addition to the Customer's other Monthly Charges.

The Company is only responsible for supplying energy to the Point of Delivery and, at its expense, may check energy consumption at any time.

SCHEDULE 40
UNMETERED GENERAL SERVICE
(Continued)

MONTHLY CHARGE

The average monthly kWh of energy usage shall be estimated by the Company, based on the Customer's electric equipment and one-twelfth of the annual hours of operation thereof. Since the service provided is unmetered, failure of the Customer's equipment will not be reason for a reduction in the Monthly Charge. The Monthly Charge shall be computed at the following rate, and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Exactions).

Energy Charge, per kWh	7.4297¢
Power Supply Adjustment, per kWh	0.4116¢
Minimum Charge, per month	$ 1.50

ADDITIONAL CHARGES

Applicable only to municipalities or agencies of federal, state, or county governments with an authorized Point of Delivery having the potential of intermittent variations in energy usage.

Intermittent Usage Charge, per unit, per month	$1.00

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 41
STREET LIGHTING SERVICE

AVAILABILITY

Service under this schedule is available throughout the Company's service area within the State of Oregon where street lighting wires and fixtures can be installed on the Company's existing distribution facilities.

APPLICABILITY

Service under this schedule is applicable to service required by municipalities or agencies of federal, state, or county governments for the lighting of public streets, alleys, public grounds, and thoroughfares. Street lighting lamps will be energized each night from dusk until dawn.

SERVICE LOCATION AND PERIOD

Street lighting facility locations, type of unit and lamp sizes, as changed from time to time by written request of the Customer and agreed to by the Company, shall be provided for Customers receiving service under this schedule. The in-service date for each street lighting facility shall also be maintained.

The minimum service period for any street lighting facility is 10 years. The Company, upon written notification from the Customer, will remove a street lighting facility:

1. At no cost to the Customer, if such facility has been in service for no less than the minimum service period. The Company will not grant a request from the Customer for reinstallation of street lighting service for a minimum period of two years from the date of removal.

2. Upon payment to the Company of the removal cost, if such facility has been in service for less than the minimum service period.

"A" - OVERHEAD LIGHTING - COMPANY-OWNED SYSTEM

The facilities required for supplying service, including fixture, lamp, control relay, mast arm for mounting on an existing utility pole, and energy for the operation thereof, are supplied, installed, owned and maintained by the Company. All necessary repairs and maintenance work, including group lamp replacement and glassware cleaning, will be performed by the Company during the regularly scheduled working hours of the Company on the Company's schedule. Individual lamps will be replaced on burnout as soon as reasonably possible after notification by the Customer and subject to the Company's operating schedules and requirements.

The Company has two standard street lighting fixture options, drop-glass or cut-off (shielded lighting). For each initial lighting fixture installation, the Customer is required to state, in writing, a fixture preference. A maintenance-related replacement of a current fixture will be made with a similar type of drop-glass or cut-off fixture as the one being replaced unless written notification has been received from the Customer requesting a change in fixture types.

SCHEDULE 41
STREET LIGHTING SERVICE
(Continued)

ACCELERATED REPLACEMENT OF EXISTING FIXTURES

In the event a Customer requests the Company perform an accelerated replacement of existing fixtures with the cut-off fixture, the following charges will apply:

1. The designed cost estimate which includes labor, time, and mileage costs for the removal of the existing street lighting fixtures.

2. $65.00 per fixture removed from service.

The total charges identified in 1 and 2 above must be paid prior to the beginning of the fixture replacement and are non-refundable. The accelerated replacement will be performed by the Company during the regularly scheduled working hours of the Company and on the Company's schedule.

MONTHLY CHARGE

The Monthly Charges are as follows, and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Exactions).

Lamp Charges, per lamp

High Pressure Sodium Vapor	Average Lumens	Monthly Base Rate	Power Supply Adjustment
70 Watt	5,540	$ 7.94	$ 0.10
100 Watt	8,550	$ 7.89	$ 0.14
200 Watt	19,800	$ 9.53	$ 0.28
250 Watt	24,750	$ 10.54	$ 0.35
400 Watt	45,000	$ 13.15	$ 0.56

Pole Charges
For Company-owned poles required to be used for street lighting only:

Wood pole	$ 1.90 per pole
Steel pole	$ 7.39 per pole

Facilities Charges
Customers assessed a monthly facilities charge prior to August 8, 2005 for the installation of underground circuits will continue to be assessed a monthly facilities charge equal to 1.75 percent of the estimated cost difference between overhead and underground circuits.

SCHEDULE 41
STREET LIGHTING SERVICE
(Continued)

"B" - CUSTOMER-OWNED SYSTEM

The Customer's lighting system, including posts or standards, fixtures, initial installation of lamps and underground cables with suitable terminals for connection to the Company's distribution system, is installed and owned by the Customer.

Customer-owned systems constructed, operated, or modified in such a way as to allow for the potential or actual variation in energy usage, such as through, but not limited to, the use of wired outlets or useable plug-ins, are required to be metered in order to record actual energy usage.

ENERGY AND MAINTENANCE SERVICE

Energy and Maintenance Service includes operation of the system, energy, lamp renewals, cleaning of glassware, and replacement of defective photocells which are standard to the Company-owned street light units. Service does not include the labor or material cost of replacing cables, standards, broken glassware or fixtures, painting, or refinishing of metal poles. Individual lamps will be replaced on burnout as soon as reasonably possible after notification by the Customer and subject to the Company's operating schedules and requirements.

ENERGY ONLY SERVICE

Energy-Only Service is available only to a metered lighting system. Service includes energy supplied from the Company's overhead or underground circuits and does not include any maintenance to the Customer's facilities.

A street lighting system receiving service under the Energy-Only Service offering is not eligible to transfer to any street lighting service option under this schedule that includes maintenance provisions to the Customer's facilities.

SCHEDULE 41
STREET LIGHTING SERVICE
(Continued)

MONTHLY CHARGE

The Monthly Charges are as follows, and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Exactions).

Non-Metered Service (With Maintenance), per lamp

High Pressure Sodium Vapor	Average Lumens	Monthly Base Rate	Power Supply Adjustment
70 Watt	5,540	$ 4.44	$ 0.10
100 Watt	8,550	$ 4.63	$ 0.14
200 Watt	19,800	$ 6.28	$ 0.28
250 Watt	24,750	$ 7.28	$ 0.35
400 Watt	45,000	$ 9.89	$ 0.56

Metered Service (With Maintenance), per lamp

Lamp Charge, per lamp	
High Pressure Sodium Vapor	
70 Watt	$ 2.86
100 Watt	$ 2.60
200 Watt	$ 2.73
250 Watt	$ 2.92
400 Watt	$ 3.23
Meter Charge, per meter	$ 8.00
Energy Charge, per kWh	4.4984¢
Power Supply Adjustment, per kWh	0.4116¢

Metered Energy-Only Service (No Maintenance)

Meter Charge, per meter	$ 8.00
Energy Charge, per kWh	4.4984¢
Power Supply Adjustment, per kWh	0.4116¢

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 42
TRAFFIC CONTROL SIGNAL
LIGHTING SERVICE

APPLICABILITY

Service under this schedule is applicable to Electric Service required for the operation of traffic control signal lights within the State of Oregon. Traffic control signal lamps are mounted on posts or standards by means of brackets, mast arms, or cable.

CHARACTER OF SERVICE

The traffic control signal fixtures, including posts or standards, brackets, mast arm, cable, lamps, control mechanisms, fixtures, service cable, and conduit to the point of, and with suitable terminals for, connection to the Company's underground or overhead distribution system, are installed, owned, maintained and operated by the Customer. Service is limited to the supply of energy only for the operation of traffic control signal lights.

The installation of a meter to record actual energy consumption is required for all new traffic control signal lighting systems installed on or after August 8, 2005. For traffic control signal lighting systems installed prior to August 8, 2005 a meter may be installed to record actual usage upon the mutual consent of the Customer and the Company.

MONTHLY CHARGE

The monthly kWh of energy usage shall be either the amount estimated by the Company based on the number and size of lamps burning simultaneously in each signal and the average number of hours per day the signal is operated, or the actual meter reading as applicable. The Monthly Charge shall be computed at the following rate, and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Exactions).

Energy Charge, per kWh	7.4265¢
Power Supply Adjustment, per kWh	0.4116¢

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 55
ANNUAL POWER COST UPDATE

PURPOSE

The purpose of this adjustment schedule is to define procedures for annual rate revisions due to changes in the Company's projected Net Power Supply Expense. This schedule is an "automatic adjustment clause" as defined in ORS 757.210(1). The Annual Power Cost Update (APCU) will be comprised of two components: an October Power Cost Update ("October Update") and a March Power Cost Forecast ("March Forecast").

APPLICABILITY

This schedule is applicable to all electric energy delivered to Customers served under Schedules 1, 7, 9, 15, 19, 24, 40, 41, and 42.

NET POWER SUPPLY EXPENSE

Net Power Supply Expense (NPSE) includes the amounts booked to FERC Accounts 501 (Fuel-Coal), 547 (Fuel-Gas), 555 (Purchased Power), and 447 (Sales for Resale).

RATES

This adjustment rate is subject to increases or decreases which may be made without prior hearing to reflect increases or decreases, or both, in NPSE.

APCU - OCTOBER UPDATE

The October update filing, which will be based on a test period of the following April through March ("April through March Test Period"), will reflect a normalized look, on a system-wide basis, at the Company's NPSE. A normalized look means the October update will incorporate data reflecting normal loads and average costs associated with multiple stream flow conditions.

The following variables are updated for each October Update:

- Fuel prices and transportation costs;
- Wheeling expenses;
- Planned outages and forced outage rates;
- Heat rates;
- Forecast of Normalized Sales and Normalized Load determined in accordance with the methodology employed in the most recently acknowledged Integrated Resource Plan ("IRP");
- Contracts for wholesale power and power purchases and sales;
- PURPA contract expenses;
- The Oregon state allocation factor; and
- The average forward electric price curve calculated from the previous October through September daily Mid-Columbia heavy load and light load forward price curves for the period April through March immediately following the April through March Test Period, adjusted for inflation back one year.

SCHEDULE 55
ANNUAL POWER COST UPDATE
(Continued)

APCU - OCTOBER UPDATE (Continued)

The output of the Company's power supply model will be used to determine the net power supply average dispatch for normal loads and an average of stream flow conditions. The volume of purchased power and surplus sales determined from the output of the Company's power supply model normalized run will be re-priced using the average forward price curve modified in the following manner:

Purchased Power

- Heavy Load - 3.9% above average Mid-C HL prices
- Light Load - 7.1% above average Mid-C LL prices

Surplus Sales

- Heavy Load - 3.6% below average Mid-C HL prices
- Light Load - 6.6% below average Mid-C LL prices

The October Update Rate for power supply expense will be the Base Power Costs divided by the Normalized Sales. Base Power Costs are the total power supply expense dollars determined by the procedures described above.

APCU - MARCH FORECAST

The March Forecast filing will reflect the Company's estimate of expected power supply expenses for April through March Test Period, allowing for the most recent updates to the following variables:

- Fuel prices and transportation costs;
- Wheeling expenses;
- Planned outages and forced outage rates;
- Heat rates;
- Forecast of Normalized Sales and Normalized Loads, updated only for known significant changes since the October Annual Power Cost Update filing;
- Forecast hydro generation from stream flow conditions using the most recent water supply forecast from the Northwest River Forecast Center in Portland, Oregon, and current reservoir levels;
- Contracts for wholesale power and power purchases and sales;
- PURPA contract expenses;
- The Oregon state allocation factor; and
- The most recent monthly forward price curve, as of the date of the filing, for the April through March Test Period.

The output of a single water condition run of the Company's power supply model for the April through March Test Period, with updated stream flow conditions and reservoir levels, will be used to determine the March Forecast of NPSE. The volume of purchased power and surplus sales will be re-priced using the most recent monthly forward price curve, with heavy load and light load mid-Columbia prices modified in the following manner.

SCHEDULE 55
ANNUAL POWER COST UPDATE
(Continued)

APCU - MARCH FORECAST (Continued)

Purchased Power

- Heavy Load - 3.9% above average Mid-C HL prices
- Light Load - 7.1% above average Mid-C LL prices

Surplus Sales

- Heavy Load - 3.6% below average Mid-C HL prices
- Light Load - 6.6% below average Mid-C LL prices

The March Forecast Rate for power supply expense will be the Forecast Power Costs determined by the procedures described above, divided by the Forecast Normalized sales.

CHANGES IN NET POWER SUPPLY EXPENSE

Changes in NPSE are defined as the projected per unit change in NPSE from the per unit NPSE used to develop the Energy Charge for the applicable rate schedules. Unit NPSE are defined as the total NPSE divided by Normalized Sales for the April through March Test Period.

FILING AND EFFECTIVE DATE

In October of each year, the Company will file its October Update with an effective date of June 1 of the following year.

In March of each year the Company will file its March Forecast with an effective date of June 1 following the filing.

RATE ADJUSTMENT

The Sales Adjusted Forecast Power Cost Change is the March Forecast Rate less the October Update Rate, the result multiplied by the Forecast Sales.

The Forecast Change Allowed is 95% of the Sales Adjusted Forecast Power Cost charge.

The March Forecast Rate Adjustment is the Forecast Change Allowed divided by Forecast Sales.

The Combined Rate is the sum of the October Update Rate and the March Forecast Rate Adjustment.

The rate adjustment is the difference between the Combined Rate and the unit NPSE included in the current base rate. The rate adjustment is applied to each of the schedules on an equal cents per kWh basis.

ADJUSTMENT RATES

Schedule	Description	¢ per kWh
1	Residential Service	1.2570
7	Small General Service	1.2570
9	Large Power Service	1.2570
15	Dusk to Dawn Lighting	1.2570
19	Large Power Service	1.2570
24	Irrigation Service	1.2570
40	Unmetered General Service	1.2570
41	Municipal Street Lighting	1.2570
42	Traffic Control Lighting	1.2570

SCHEDULE 56
POWER COST ADJUSTMENT MECHANISM

PURPOSE

To recognize in rates part of the difference between actual net power supply expenses incurred for the preceding January through December period and the net power supply expenses recovered through Schedule 55 for that same period.

APPLICABILITY

This schedule is applicable to all electric energy delivered to Customers served under Schedules 1, 7, 9, 15, 19, 24, 40, 41 and 42.

ANNUAL POWER COST ADJUSTMENT (PCA)

Subject to the 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.

ANNUAL POWER SUPPLY EXPENSE TRUE-UP BALANCING ACCOUNT (TRUE-UP BALANCING ACCOUNT)

The True-Up Balancing Account is a Company account where the PCA will be added at the end of each 12-month period ending December, along with 50 percent of the annual interest calculated at the Company's authorized cost of capital. Interest will accrue on the True-Up Balancing Account at the Commission-authorized rate for deferred accounts.

EARNINGS TEST

Before any PCA amount is approved for inclusion in the True-Up Balancing Account for subsequent recovery or refund in rates, the Commission will apply an Earnings Test.

If the Company'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 PCA 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 PCA amount 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 PCA amount in the True-Up Balancing Account as a credit, down to the authorized ROE plus 100 basis points threshold.

DEFINITIONS

Actual Net Power Supply Expenses (Actual NPSE)

Actual NPSE is determined on a system-wide basis and includes the amounts booked to FERC Accounts 501 (Fuel-Coal), 547 (Fuel-Gas), 555 (Purchased Power), and 447 (Sales for Resale).

SCHEDULE 56
POWER COST ADJUSTMENT MECHANISM
(Continued)

DEFINITIONS (Continued)

Actual Sales

Actual Sales is the amount of energy required to meet customer demand on a system-wide basis, as measured at the customers' meters.

Actual Unit Cost

The Actual Unit Cost for net power supply expenses incurred is the total Actual NPSE incurred divided by Actual Sales.

Combined Rate

The Combined Rate is the sum of the October Update Rate and the March Forecast Rate Adjustment, as determined by the Annual Power Cost Update, Schedule 55.

Normalized Sales

Normalized Sales is a forecast of the amount of energy required to meet customer demand on a system-wide basis, as measured at the customers' meters, determined in accordance with the methodology employed in the Company's most recently acknowledged Integrated Resource Plan ("IRP").

Oregon Allocated Power Cost Deviation

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.

Power Supply Expense Deadband

A Power Supply Expense Deadband (Deadband) based upon the Company's authorized ROE from its last general rate case and using the rate base measured on an Oregon basis from the most recent Oregon Results of Operations report (Oregon basis), is applied to the Oregon Allocated Power Cost Deviation as follows:

1. 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).

2. 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).

SCHEDULE 56
POWER COST ADJUSTMENT MECHANISM
(Continued)

ANNUAL POWER SUPPLY EXPENSE TRUE-UP

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.

TIME OF FILING

In February of each year, beginning in February of 2009, the Company will file the Annual Power Supply Expense True-Up which will implement the Power Cost Adjustment Mechanism. This filing will calculate 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 costs are first calculated on a total system basis and then allocated to Oregon based on the allocation factor.

TRUE-UP RATES

The True-Up Rates (Annual Power Supply Expense True-Up) will be determined on an equal cents per kWh basis. The True-Up Rates are:

Schedule	Description	¢ per kWh
1	Residential Service	0.0000
7	Small General Service	0.0000
9	Large Power Service	0.0000
15	Dusk to Dawn Lighting	0.0000
19	Large Power Service	0.0000
24	Irrigation Service	0.0000
40	Unmetered General Service	0.0000
41	Municipal Street Lighting	0.0000
42	Traffic control Lighting	0.0000

SCHEDULE 60
SOLAR PHOTOVOLTAIC SERVICE
PILOT PROGRAM

AVAILABILITY

Service under this schedule is available to Customers who have entered into a Uniform Solar Photovoltaic Service Agreement with the Company. New service under this schedule will not be available after November 15, 1996.

DEFINITIONS

Photovoltaic System is the solar photovoltaic module(s), the module mounting structure, the control structure, the control equipment, any necessary wiring, any batteries and/or back-up generator, if required, and any other equipment necessary to provide service under this schedule. The Company shall have sole ownership of the Photovoltaic System during the term of the Uniform Solar Photovoltaic Service Agreement.

Point of Service is the point where the Customer's electric system is connected to the Photovoltaic System.

Total Installed Cost is the estimated total cost for the installation of, or modification to, the Photovoltaic System including but not limited to the Company's investment in facilities, labor, material and supplies, and overheads.

Net Installed Cost is the Total Installed Cost less the Initial Fee.

Customer Site is the installation site and facilities as determined by the Company which are necessary for the installation of the Photovoltaic System. The Customer Site facilities are not included as part of the Photovoltaic System unless specifically stated by the Company and included in the Solar Photovoltaic Facilities Investment Report.

Salvage Value is the market value of the photovoltaic facilities at the time they are removed from the Customer's premises.

Facility Termination Charge is the Total Installed Cost of the Photovoltaic System less the sum of 80 percent of the accumulated depreciation and 60 percent of the Salvage Value of the facilities removed plus the removal cost. In no event will the Facility Termination Charge be less than the removal cost.

ELIGIBILITY

Requests for service under this schedule which have a Total Installed Cost of no more than $50,000, which are located in areas reasonably accessible by standard utility vehicles, and which are cost effective alternatives are eligible for service under this schedule. In determining eligibility under this schedule, the Company will consider the remoteness, accessibility, load size, load profile, solar resource, and solar impediments of the requested site as well as the suitability of the Customer Site. Requests which have special access requirements may be granted at the discretion of the Company provided that reasonable alternative access provisions are met and/or the Company is compensated for its special access related costs. Any special access provisions will be included in an addendum to the Uniform Solar Photovoltaic Service Agreement. The Company has the sole right to ultimately determine eligibility under this schedule.

SCHEDULE 60
SOLAR PHOTOVOLTAIC SERVICE
PILOT PROGRAM
(Continued)

INITIAL FEE

An Initial Fee equal to 5 percent of the Total Installed Cost of the Photovoltaic System is required from the Customer at the time the Uniform Solar Photovoltaic Service Agreement is executed. If a modification to the Photovoltaic System which increases the Total Installed Cost is requested subsequent to the time the Uniform Solar Photovoltaic Service Agreement is executed, an additional Initial Fee equal to 5 percent of the Total Installed Cost of the modification will be required prior to the installation of such modification to the Photovoltaic System. The Initial Fee is non-refundable unless the Company determines that it will not install the Photovoltaic System.

SERVICES PROVIDED

The Photovoltaic System will be specified by the Company based upon the service requirements requested by the Customer. Upon determination by the Company that the Customer is eligible for service under this schedule, and upon receipt from the Customer of the Initial Fee, the Company will proceed with the installation plans for the Photovoltaic System.

All repair and maintenance of the Photovoltaic System will be provided by the Company. Prudent utility practices will be followed for all necessary repair or maintenance. The Company will use its best effort to provide the Customer a minimum of 24 hours notice prior to performing preventative maintenance.

The Customer is responsible for providing the Customer Site and the connections from the Point of Service to the Customer's facilities, and for permitting the Company appropriate access to the Photovoltaic System. The Customer Site and Customer connections must be approved by the Company and must meet all State and Local Codes. The Company may, at its sole discretion, install and/or own Customer Site facilities and include the cost of such facilities in the Total Installed Cost.

If a back-up generator is included with the Photovoltaic System, the Customer is responsible for providing, at the Customer's expense, the fuel required for the operation of such generator.

SERVICE LIMITATIONS

Electric service under this schedule is limited to that provided by the Photovoltaic System. The Company is under no obligation to provide Electric Service to the Customer at any time by means of the Company's transmission or distribution system.

CUSTOMER NON-COMPLIANCE

Any use by the Customer of the Photovoltaic System not in compliance with the design specifications for such system or not in compliance with the provisions of this schedule may result in the removal by the Company of the Photovoltaic System. The Company reserves the right to remove the Photovoltaic System if the Company determines that the continued use of the facilities by the Customer poses a threat of injury or damage to persons or property. Non-payment of the monthly charges under this schedule may also result in the removal by the Company of the Photovoltaic System.

In the event the Company removes the Photovoltaic System under the provisions of this section, the Customer will be obligated to pay to the Company the Facility Termination Charge.

SCHEDULE 60
SOLAR PHOTOVOLTAIC SERVICE
PILOT PROGRAM
(Continued)

SOLAR PHOTOVOLTAIC FACILITIES INVESTMENT REPORT

The Total Installed Cost of the Photovoltaic System will be set forth in a Solar Photovoltaic Facilities Investment Report provided to the Customer. The monthly charge for service under this schedule is based on the Total Installed Cost, less the Initial Fee, as reflected on this Report. When the actual book cost of the installed Photovoltaic System has been determined by the Company, the Total Installed Cost will be adjusted to reflect the actual cost and the corresponding monthly charge will be reduced if the actual cost is more than 10 percent less than the Total Installed Cost included on the Report. In no event will the monthly charge be increased if the actual cost is greater than the Total Installed Cost.

PHOTOVOLTAIC SYSTEM MODIFICATIONS

If the Photovoltaic System is modified in order to provide for changes in the Customer's service requirements, the Solar Photovoltaic Facilities Investment Report and the corresponding monthly charge for service will be adjusted to reflect the modification.

Additions. If the Customer requests a modification to the Photovoltaic System, the Customer will be required to pay an additional Initial Fee equal to 5 percent of the Total Installed Cost of the modification prior to the installation of the modification.

Removals. If the Customer requests a portion of the Photovoltaic System be removed, the Customer shall pay to the Company the Facility Termination Charge for that portion of the Photovoltaic System removed. If the Customer requests the Photovoltaic System in its entirety be removed, the provisions of the Agreement Termination section below will apply.

AGREEMENT TERMINATION

Customer Termination. If the Customer cancels the Uniform Solar Photovoltaic Service Agreement at the end of any of the five year terms of the Agreement, the Customer shall have the option of either 1) purchasing the Photovoltaic System at the Company's Total Installed Cost less accumulated depreciation, or 2) requesting the Company remove the Photovoltaic System and paying to the Company the cost of removing the facilities. If the Customer cancels the Uniform Solar Photovoltaic Service Agreement during the term of the Agreement, the Customer shall pay to the Company the Facility Termination Charge.

Company Termination. If the Company cancels the Uniform Solar Photovoltaic Service Agreement at any time and for any reason other than Customer Non-Compliance, the Company shall offer the Customer the option of either; (1) purchasing the Photovoltaic System at the Company's Total Installed Cost less accumulated depreciation, or (2) requesting the Company remove the Photovoltaic System at no cost to the Customer.

SCHEDULE 60
SOLAR PHOTOVOLTAIC SERVICE
PILOT PROGRAM
(Continued)

CHARGES

The monthly charge for service under this schedule is 1.6 percent times the Net Installed Cost of the Photovoltaic System as set forth on the Solar Photovoltaic Facilities Investment Report.

Back-up Generator Maintenance Charge: If the hours of usage of a back-up generator included with the Photovoltaic System exceeds the number of hours of usage specified in the design specifications by 20 percent or more on an annual basis, the Customer will be responsible for paying the additional maintenance costs incurred by the Company as a result of such overuse. The Company will notify the Customer in writing of any observed overuse of the back-up generator.

PAYMENT

The monthly bill rendered for service provided hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 60
SOLAR PHOTOVOLTAIC SERVICE
PILOT PROGRAM

IDAHO POWER COMPANY
Uniform Solar Photovoltaic
Service Agreement

DISTRICT ______________________ ACCOUNT NO. ______________________________________

THIS AGREEMENT Made this _______ day of _____________, 19 _______, between _______________ ____, whose billing address is____ hereinafter called Customer, and IDAHO POWER COMPANY, A corporation with its principal office located at 1221 West Idaho Street, Boise, Idaho, hereinafter called Company:

NOW THEREFORE, The parties agree as follows:

1. Company will provide solar photovoltaic service for Customer's facilities located at or near

____________________________, County of ____________________________________, State of Oregon.

2. Customer will:

a. Make an Initial Fee payment to the Company of $_____________ at the time this Agreement is executed.

b. Provide the installation site and facilities as determined by the Company which are necessary for the installation of the Photovoltaic System and which are acceptable to the Company, and the right of the Company for appropriate access to the Company's facilities with the right of ingress and egress, at no cost to the Company.

3. This Agreement will not become binding upon the parties until signed by both parties.

4. The initial date of service under this Agreement is subject to the Company's ability to obtain the required labor, materials, and equipment, a satisfactory site, and satisfactory access to the Photovoltaic System on the Customer's property, and to comply with governmental regulations.

5. The term of this Agreement will be for five years from and after the Initial Service Date thereof, and will automatically renew for an additional five years each five years thereafter unless canceled by either party. This Agreement may be canceled 1) by either party after any of the five year terms provided written notice of termination is given to the other not less than three months prior to the end of the five year term, or 2) at any time provided both parties agree in writing to the cancellation. In the event the Company's Schedule 60 is terminated during the term of this Agreement, this Agreement will automatically be canceled and the Customer will have the option to purchase the Photovoltaic System at the Company's depreciated book value.

6. This Agreement will be binding upon the respective successors and assigns of the Customer and the Company, provided however, that no assignment by the Customer will be effective without the Company's prior written consent. The Company's consent will not be unreasonably withheld.

7. This Agreement is subject to valid laws and to the regulatory authority and orders, rules and regulations of the Oregon Public Utility Commission as now or may be hereafter modified and approved by the Oregon Public Utility Commission.

IDAHO POWER COMPANY
Uniform Solar Photovoltaic
Service Agreement
(Continued)

8. The Company's Schedule 60, as well as Idaho Power Company's General Rules and Regulations, any revisions to Schedule 60 or to the General Rules and Regulations, and/or any successor schedule or rules, are to be considered as part of this Agreement.

9. The Company will not be held responsible or liable for any loss, damage, or injury caused to its Customer or any other persons by the interruption, suspension, or fluctuation in service provided by the Photovoltaic System.

10. The Customer will agree to protect, defend, and indemnify Idaho Power Company from and against any costs, damages, or claims arising in any way from any injury to persons or damage to property resulting from the installation and/or operation of the Photovoltaic System upon Customer's property, providing such injury to persons or damage to property is not due to the sole negligence of Idaho Power Company.

11. In any action at law or equity commenced under this Agreement and upon which judgment is rendered, the prevailing party, as part of such judgment, will be entitled to recover all costs, including reasonable attorneys fees, incurred on account of such action.

Date ______________________, 19______

Initial Service Date______________________

(APPROPRIATE SIGNATURES)

SCHEDULE 61
POWER QUALITY PROGRAM

AVAILABILITY

Service under this Schedule is available to Customers throughout the Company's service area within the State of Oregon.

PROGRAM DESCRIPTION

The Power Quality Program is intended to provide Customers with a mechanism to identify and correct electrical problems within the Customer's residence or business which impact the Customer's power quality.

SERVICES PROVIDED

The Company will provide the following services:

Technical Assistance: The Company will perform a symptomatic audit of the Customer's residence or business to assist the Customer in identifying the probable cause of any power quality problems and possible solutions to any power quality problems identified. Technical Assistance is provided at no charge to the Customer.

Home Wiring Audit: A $40 payment is provided by the Company to residential Customers who have a home wiring audit performed by a licensed electrician participating. To have a home wiring audit performed, a Customer is responsible for contacting the Company to request the Home Wiring Audit form and then contacting a licensed electrician to perform the audit. The Customer is also responsible for ensuring the electrician performs the audit per the instructions of the Home Wiring Audit form. The charge for the audit will be established by the electrician and will be billed by the electrician directly to the Customer. The Customer is responsible for paying the electrician the charge for performing the audit.

The $40 payment is provided to the Customer upon receipt by the Company of the appropriate copy of the completed Home Wiring Audit form. The Customer is responsible for submitting the Home Wiring Audit form to the Company.

Purpose of Payment: The purpose of the $40 payment is to assist the Customer in identifying any wiring deficiencies that may be causing power usage problems. The payment is not an indication that the Company has performed any analysis as to the safety of the Customer's wiring or that the Company concurs with the findings of the electrician's wiring audit.

SCHEDULE 62
GREEN ENERGY PURCHASE PROGRAM RIDER
(OPTIONAL)

PURPOSE

The Green Energy Purchase Program is an optional, voluntary program designed to provide customers an opportunity to participate in the purchase of new environmentally friendly "green" energy. Funds collected in this program will be wholly distributed to the purchase of Green Energy Products.

APPLICABILITY

Service under this schedule is applicable to all Customers and non-customers who choose to participate in this Program.

MONTHLY GREEN ENERGY PURCHASE CONTRIBUTION

Customers designate their level of participation by choosing a fixed dollar per month amount. The monthly Green Energy Purchase Program contribution is in addition to all other charges included in the service schedule under which the Customer receives electrical service and will be added to the Customer's monthly electric bill. Non-Customer participants will be issued a monthly invoice that reflects their designated fixed dollar per month contribution.

The Program funds will wholly be used to purchase green energy or to cover the green energy price premium. The Company will acquire Green Energy Products within one year of the Customer's purchase under this Schedule.

GREEN ENERGY PRODUCTS

For purposes of this Program, green energy products include but are not limited to the following:

Green Tags. Green tags consist of the Non-Power Attributes resulting from the generation of energy by a qualified renewable resource. Such attributes may be fuel, emissions, or other environmental characteristics deemed of value by a green tag buyer. The price of Green Tags may include administration costs of the Green Tag broker.

Non-Power Attributes include but are not limited to any avoided emissions of pollutants to the air, soil or water such as sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO) and any other pollutant that is now or may in the future be regulated under the pollution control laws of the United States; and further include any avoided emissions of carbon dioxide (CO_2), methane (CH_4) and any other greenhouse gas (GHG) that contributes to the actual or potential threat of altering the Earth's climate. Non-Power Attributes are expressed in MWh.

Non-Power Attributes do not include any energy, capacity, reliability or other power attributes used to provide electricity services.

PROGRAM CONSIDERATIONS

No electric service disconnections will result in the event of non-payment of Program commitments.

SCHEDULE 66
MISCELLANEOUS CHARGES

PURPOSE

The purpose of this schedule is to accumulate all miscellaneous charges that are included in the Company's Rules, Regulations, and Rates.

APPLICABILITY

This schedule applies to all Customers taking service under the Company's Oregon Tariff except as expressly limited by a Rule or a Schedule.

CHARGES

RULE D

1. Instrument Transformer Metering

Current Transformer

Single Phase	
120/240 Volt	$214.00
240/480 Volt	$247.00
120/208 Volt Network	$275.00
Polyphase	
120/240 Volt Delta	$437.00
240/480 Volt Delta	$438.00
120/208 Volt Wye	$467.00
277/480 Volt Wye	$471.00

Voltage Transformer (secondary voltages only)

Additional cost per voltage transformer	$160.00

Primary Metering

Work Order costs are applicable.

2. Off-Site Meter Reading Service

Single-Phase, Non-Demand Metering

Class 200 R300 Register (standard metering)	$ 3.65 per month
Class 320 R300 Register (standard metering)	$ 4.40 per month
Class 10 R 300 Register (instrument transformer metering)	$ 4.40 per month
Installation Fee (payable with first monthly payment)	$ 25.00
Removal Fee (if removed within 90 days of installation)	$ 25.00

SCHEDULE 66
MISCELLANEOUS CHARGES
(Continued)

RULE D (Continued)

3. Load Profile Metering

Pulse Output Service

With an existing Electronic Demand Meter	$ 5.00 per month
Without an existing Electronic Demand Meter	$ 13.00 per month
Installation Fee (payable with first monthly payment)	$ 70.00
Removal Fee (if removed within 90 days of installation)	$ 60.00

Load Profile Recording Service

With an existing Electronic Demand Meter	$ 17.50 per month
Without an existing Electronic Demand Meter	$ 25.50 per month
Installation Fee (payable with first monthly payment)	$ 80.00
Removal Fee (if removed within 90 days of installation)	$ 60.00

4. Special Meter Test

Non-Residential	Actual Labor & Mileage Rates
Residential	Not to Exceed $30.00

5. Surge Protection Device Services

Surge Protection Device Installation or Removal Charge	$ 43.00
Surge Protection Device Customer Visit Charge	$ 25.00

RULE F (all times are stated in Mountain Time)

6. Service Establishment Charge	$ 20.00
7. Continuous Service Reversion Charge	$ 10.00
8. Field Visit Charge	$ 20.00

9. Service Connection Charge

Schedules 1, 7, 9

Monday through Friday

7:30 am to 6:00 pm	$ 20.00
6:01 pm to 9:00 pm	$ 45.00
9:01 pm to 7:29 am	$ 80.00

Company Holidays and Weekends

7:30 am to 9:00 pm	$ 45.00
9:01 pm to 7:29 am	$ 80.00

SCHEDULE 66
MISCELLANEOUS CHARGES
(Continued)

RULE F (all times are stated in Mountain Time) (Continued)

9. Service Connection Charge (Continued)

Schedules 15, 19, 24, 40, 41, 42	
Monday through Friday	
7:30 am to 6:00 pm	$ 40.00
6:01 pm to 9:00 pm	$ 65.00
9:01 pm to 7:29 am	$100.00
Company Holidays and Weekends	
7:30 am to 9:00 pm	$ 65.00
9:01 pm to 7:29 am	$100.00

10. Unauthorized Reconnection Charge $ 50.00

RULE G

11. Returned Check Charge $ 20.00

12. Fractional Period Minimum Billings

Schedules 1 and 7	$ 3.00
Schedules 9 and 19 Secondary	$ 5.00
Schedules 9 and 19 Primary & Transmission	$ 10.00
Schedule 24	$ 3.00
Schedule 15	$ 3.00
Schedule 40	$ 1.50

RULE H

13. Temporary Service Return Trip Charge $ 35.00

SCHEDULE 70
APPLIANCE RECYCLING PROGRAM

This schedule describes the Appliance Recycling Program (Program) offered by the Company and coordinated by JACO Environmental, Inc (JACO).

AVAILABILITY

This program is available to residential customers living in single and multi-family residences, including manufactured and modular homes, who remove and recycle a refrigerator or freezer and who live within the Company's service territory within the State of Oregon.

PROGRAM DESCRIPTION

The Appliance Recycling Program is an incentive-based program designed to encourage the removal and recycling of less efficient appliances by providing a $30 incentive to participating customers. To participate, Customers will schedule an appointment with JACO by phone or website to have their unit collected. JACO will pick up the unit from the Customer's home, transport, dismantle and recycle the unit.

TERMS AND CONDITIONS

By participating in the Program, Customers will be subject to the following terms and conditions:

1. Functioning units only.
2. Secondary units are preferred but incentive is available for the replacement of a primary unit.
3. Unit must be 10 to 30 cubic feet.
4. Clear path of removal must exist.
5. Maximum participation of two units per customer, per year.

SCHEDULE 71
DUCTLESS HEAT PUMP
PILOT PROGRAM

This Schedule describes the Ductless Heat Pump Pilot Program offered by the Company and coordinated by the Northwest Energy Efficiency Alliance (NEEA).

AVAILABILITY

This program is available to residential customers living in single-family residences, including manufactured homes with permanent foundations, where no natural gas service is available, who live within the Company's service territory within the State of Oregon and have a ductless heat pump installed.

APPLICABILITY

Service under this schedule applies to customers who have lived in their home at least one full year prior to participation in the Ductless Heat Pump Pilot Program, have used electric heat as their primary heating source for the past year, and expect to live in their home for the two years following installation. The Program will commence on April 22, 2009. Equipment installation can occur until December 31, 2009 and field monitoring on installed equipment will occur through December 31, 2010.

PROGRAM DESCRIPTION

The Ductless Heat Pump Pilot Program is an incentive-based program designed to help cover a portion of the costs of installing an energy efficient ductless heat pump by providing a $1000 incentive to participating customers. The ductless heat pump installed must be a split system heat pump with an inverter driven, variable speed compressor, a variable speed outdoor fan, and a multi-speed or variable speed indoor blower. The equipment must be installed with the indoor unit located in the main living area of the house. Indoor units using any type of field-installed duct system are not eligible.

TERMS AND CONDITIONS

Upon acceptance into the Program, Customers will be subject to the following terms and conditions:

1. Participants must allow the Company to make their billing history available to the program evaluators for up to two years prior to and two years post installation,
2. Participating homes cannot be new construction, and
3. Participants must agree to the terms and conditions of the Ductless Heat Pump Pilot Program, as coordinated by NEEA.

SCHEDULE 72
HEATING AND COOLING EFFICIENCY PROGRAM

AVAILABILITY

Service under this schedule is available to residential Customers and owners or managers of rental properties throughout the Company's service area within the State of Oregon that are served under a residential electric service schedule. This schedule is also available to home builders and developers who construct homes in the Company's service area within the State of Oregon that take service under a residential electric service schedule upon completion.

APPLICABILITY

This program is applicable to site-built or manufactured homes served under a residential electric service schedule and sited in the Company's Oregon service territory.

PROGRAM DESCRIPTION

The Heating and Cooling Efficiency Program provides incentives for the proper sizing and installation of energy efficient heat pump equipment and for the purchase and installation of evaporative cooling equipment.

INCENTIVE STRUCTURE

To be eligible for an incentive, purchase and installation of the qualifying equipment cannot have started prior to May 1, 2009. Installation of heating and cooling equipment must have been performed by a participating company w ho has received program training and has signed an agreement with the Company, except for evaporative cooling equipment which does not require contractor training and installation. Installed measures must meet the requirements of the Heating and Cooling Efficiency Program as outlined in the Program Requirements Manual. To view a list of the participating companies and a current Program Requirements Manual, visit www.idahopower.com/heatingcooling.

SCHEDULE 72
HEATING AND COOLING
EFFICIENCY PROGRAM
(Continued)

INCENTIVE STRUCTURE (Continued)

Equipment/Service	Eligibility Requirements	Participant Incentive	Contractor Incentive	Notes
High Efficiency Air Source or Open Loop Water Source Heat Pump: Proper Sizing & Installation	Replacing an Existing Heat Pump			
	8.2 HSPF	$200	$150	1,2
	8.5 HSPF	$250	$150	1,2
	Minimum 3.5 COP	$500	$150	1,2
	Replacing an Existing Electric, Oil or Propane Heating System			
	8.2 HSPF	$300	$150	1,3
	8.5 HSPF	$400	$150	1,3
	Minimum 3.5 COP	$1,000	$150	1,3
Evaporative Cooler: Purchase & Installation	Unit must be equal to or greater than 2500 CFM	$150	n/a	1

Notes:

1. Existing single and multi-family site-built and manufactured homes.
2. Must replace an existing air source heat pump. First-time installations do not qualify.
3. Must replace an oil/propane heating system or be installed in new construction homes in areas where natural gas is not available.

QUALIFICATIONS

In order to receive a financial incentive under this program, each participating customer must complete the following steps

1. Select a participating company.
2. Purchase high efficiency equipment that meets program requirements.
3. Have participating company properly size and install qualified equipment according to program requirements.
4. Complete and sign the customer portion of the incentive application supplied by the participating company. The participating company will submit the application paperwork on the customer's behalf.

SCHEDULE 73
HOME PRODUCTS PROGRAM
(OPTIONAL)

AVAILABILITY

This program is available to residential customers living in single and multi-family residences, including manufactured and modular homes, who purchase qualified ENERGY STAR® home products and install them in a home within the Company's service territory within the State of Oregon.

APPLICABILITY

Service under this schedule applies to the purchase of qualified new clothes washers, refrigerators, light fixtures, ceiling fans with light kits, or ceiling fan light kits that are certified as an ENERGY STAR® product. ENERGY STAR® is a government-backed program that designates products as energy efficient. Products labeled as ENERGY STAR® must meet higher, stricter energy efficiency criteria than federal standards. ENERGY STAR® qualified home products use advanced technologies and consume 10-50 percent less energy.

PROGRAM DESCRIPTION

The Home Products Program is an incentive-based program designed to help cover a portion of the costs of purchasing qualified energy efficient clothes washers, refrigerators, light fixtures, ceiling fans with light kits, or ceiling fan light kits.

INCENTIVE STRUCTURE

To be eligible for an incentive, purchase and installation of the qualifying products cannot have started prior to July 30, 2008.

Equipment Category	Incentive per Unit	Notes
Clothes Washers	$50	1
Refrigerators	$30	2
Light Fixtures	$15	1
Ceiling Fans with Light Kits	$20	1
Ceiling Fan Light Kits	$20	1

Notes:

1) To view a list of the qualified ENERGY STAR® home products included in this equipment category, visit www.energystar.gov.

2) Only full-size refrigerators 7.75 cubic feet or larger are eligible for incentives. Although freezers and compact refrigerators are listed along with qualified full-size refrigerators on the ENERGY STAR® website, incentives are only available for the refrigerators.

SCHEDULE 73
HOME PRODUCTS PROGRAM
(OPTIONAL)

QUALIFICATIONS

In order to receive a financial incentive under this program, each participating customer must complete the following steps:

1. Purchase and install a new qualified ENERGY STAR® home product.

2. Complete the Idaho Power Home Products Incentive Application and sign it.

3. Mail the completed incentive form and a copy of the itemized sales receipt to Idaho Power.

SCHEDULE 74
RESIDENTIAL AIR CONDITIONER CYCLING PROGRAM
(OPTIONAL)

PURPOSE

The Residential Air Conditioner Cycling Program is an optional, supplemental service that permits participating residential Customers an opportunity to voluntarily allow the Company to cycle their central air conditioners with the use of a direct load control Device installed at their residence. Customers will receive a monthly monetary incentive for successfully participating in the Program during the Air Conditioning Season.

DEFINITIONS

AC Cycling is the effect of the Company sending a signal to a Device installed at the Customer's residence and instructing it to cycle the Central Air Conditioning compressor for a specified length of time.
Air Conditioning Season is the three-month period that commences on June 1 and continues through August 31 of each calendar year.

Central Air Conditioning is a home cooling system that is controlled by one or more centrally located thermostats that controls one or more refrigerated air-cooling units located outside the Customer's residence.

Cycling Event is a period during which the Company sends a signal to the Device installed at the Customer's residence, which instructs the Device to begin AC Cycling.

Device is a direct load control device installed at a Customer's residence that enables the Company to initiate AC Cycling.

Notification refers to the Customer's indication of intent to initiate or terminate participation in the Program by either contacting the Company's Customer Service Center, providing written notice or submitting an electronic Application via the Company's website.

Opt Out is the term used to describe the one-day per month during each month of the Air Conditioning Season in which the Customer may choose to temporarily not participate in AC Cycling by providing advanced Notification to the Company.

Program Operation Area describes the area in which the Program will be offered to Customers and is comprised of the Company's service territory within the State of Oregon where the infrastructure required to support AC Cycling has been installed and is operational.

SCHEDULE 74
RESIDENTIAL AIR CONDITIONER
CYCLING PROGRAM
(OPTIONAL)
(Continued)

AVAILABILITY

Service under this schedule is available on an optional basis to Customers taking service under Schedule 1 who have Central Air Conditioning located at their residences and live within the Program Operation Area. Customers may request to be added to the Program at any time during the year by providing Notification to the Company.

Service under this schedule may be limited based upon the availability of Program equipment and/or funding. The Company shall have the right to select and reject Program participants at its sole discretion based on criteria the Company considers necessary to ensure the effective operation of the Program. Selection criteria may include, but will not be limited to, energy usage, residential location, size of home, or other factors. Customers' Central Air Conditioning equipment must be fully functional and comply with the National Electric Code (NEC) standards. Customers who are renting or leasing their home must provide to the Company written proof of the express permission of the owner of the Central Air Conditioning system prior to acceptance into the program.

TERMS AND CONDITIONS

Upon acceptance into the Program, Customers will be subject to the following terms and conditions:

1. Each eligible Customer who chooses to take service under this optional schedule is thereby giving the Company or its representative permission, on reasonable notice, to enter the Customer's residence or property to install a Device and, in certain cases, either a mass memory meter or an end-use meter and to allow Idaho Power or its representative, with prior notice to the Customer, reasonable access to the Device or other Program-related equipment following its installation.

2. Customers added to the Program during the Air Conditioning Season must be effectively participating in the Program prior to the 20th day of the month in order to receive an incentive payment for that initial month.

3. A Customer may Opt Out of the Program for one day per month during each month of the Air Conditioning Season.

4. A Customer may discontinue participation in the Program without penalty by providing Notification to the Company.

5. If there is evidence of alteration, tampering, or otherwise interfering with the Company's ability to initiate a Cycling Event, the Customer's participation in the Program will be terminated and the Customer will be required to reimburse the Company for the cost of replacement or repair of the Device or other Program equipment and the Company will reverse any amounts credited to the Customer's bills during the past twelve months as a result of the Customer's participation in the Program.

SCHEDULE 74
RESIDENTIAL AIR CONDITIONER
CYCLING PROGRAM
(OPTIONAL)
(Continued)

PROGRAM DESCRIPTION

1. At the Company's expense, the Company or its representative will install a Device at the Customer's residence.

2. A financial incentive of $7.00 per month for each of the three months of the Air Conditioning Season will be paid to each Customer who successfully participates in the Program. This incentive will be paid in the form of a credit on the Customer's monthly bill for each month that the Customer successfully participates in the Program, beginning with the July bill and ending with the September bill. Incentive payments are limited to one controlled Central Air Conditioning unit per metered service point. Customer's who have more than one Central Air Conditioning unit at a metered service point may participate in the Program. A Device must be installed at each Central Air Conditioning unit. However, no additional incentive will be paid.

3. The Company will send a signal to the Device to initiate a Cycling Event. A Cycling Event may be up to four hours per day on any weekday during the Air Conditioning Season. A Cycling Event may occur over a continuous 4-hour period or may be segmented throughout the day at the Company's discretion in order to optimize available resources. Cycling Events may occur up to 40 hours each month and will not exceed a total of 120 hours per Air Conditioning Season. Mass memory meters or end-use meters may be installed on some Customers' residences or Central Air Conditioning units for program evaluation purposes. The residences or Central Air Conditioning units selected for installation of the meter shall be at the Company's sole discretion.

SPECIAL CONDITIONS

The Company is not responsible for any consequential, incidental, punitive, exemplary or indirect damage to the participating Customer or third parties that results from AC Cycling, from the Customer's participation in the Program, or of Customer's efforts to reduce peak energy use while participating in the Program.

The Company makes no warranty of merchantability or fitness for a particular purpose with respect to the Device and any and all implied warranties are disclaimed.

The Company shall have the right to select the AC Cycling schedule and the percentage of Customers' Central Air Conditioning systems to cycle at any one time, up to 100%, at its sole discretion.

The provisions of this schedule do not apply for any time period that the Company interrupts the Customer's load for a system emergency or any other time that a Customer's service is interrupted by events outside the control of the Company. The provisions of this schedule will not affect the calculation or rate of the regular Service or Energy Charges associated with a Customer's standard service schedule.

SCHEDULE 75
CHANGE A LIGHT PROGRAMS

This schedule describes the "Change a Light" Programs offered by the Company and funded by the Energy Efficiency Rider.

SPIRAL BULB PROGRAM

AVAILABILITY

This program is available to customers purchasing designated, reduced-price ENERGY STAR® light bulbs from participating retailers. Bulbs can be purchased as available on a first-come, first-served basis. The program will be effective from September 10, 2008 through December 31, 2010 or until the bulbs for the program are exhausted, whichever is earlier.

SERVICE PROVIDED

Designated ENERGY STAR® light bulbs range from 13-30 watts. Using the Energy Efficiency Rider funds, the Company will pay Fluid Market Strategies, Inc. for manufacturers' mark-down fees plus their program administration costs. The bulbs will be distributed to participating retailers and sold for a price of $1.00 per bulb. Fluid Market Strategies, Inc. will be responsible for manufacturer negotiations, retailer relationships, product pricing, sales data tracking and in-store marketing. The Company will augment in-store promotions and perform additional in-store visits, where possible.

SPECIALITY BULB PROGRAM

AVAILABILITY

This program is available to customers purchasing designated, reduced-price ENERGY STAR® light bulbs from participating retailers. Bulbs can be purchased as available on a first-come, first-served basis. The program will be effective from July 1, 2009 through September 30, 2009 or until the bulbs for the program are exhausted, whichever is earlier.

SERVICE PROVIDED

Designated ENERGY STAR® light bulbs have varying wattages but may include recessed cans, globes, three-way bulbs, dimmable, outdoor and specialty spirals. Using the Energy Efficiency Rider funds, the Company will pay Portland Energy Conservation, Inc. for manufacturers' mark-down fees plus their program administration costs. The bulbs will be distributed to participating retailers. Portland Energy Conservation, Inc. will be responsible for manufacturer negotiations, retailer relationships, product pricing, sales data tracking and in-store marketing. The Company will augment in-store promotions and perform additional in-store visits, where possible.

SCHEDULE 77
ENERGY STAR®
HOMES NORTHWEST

AVAILABILITY

Service under this schedule is available to building contractors that construct onsite, single-family homes within the Company's Oregon service territory that will take residential service under Schedule 1 upon completion.

APPLICABILITY

Service under this schedule applies to new site-built construction of single-family homes that have been certified to the ENERGY STAR Homes Northwest Builder Option Package (BOP) specification.

PROGRAM DESCRIPTION

ENERGY STAR Homes Northwest is an incentive-based program that encourages the onsite construction of energy efficient single-family homes. The Company provides a $750 incentive to building contractors whose homes include central air conditioning and meet the qualifications of ENERGY STAR Homes Northwest. The ENERGY STAR Homes Northwest BOP specification is based upon the building standard developed by the Environmental Protection Agency and the US Department of Energy through support from the Northwest Energy Efficiency Alliance (the Alliance). Through a cooperative effort with the Alliance, the Company will also provide education and information about energy efficient home construction to building contractors and consumers.

QUALIFICATIONS

Each participating building contractor must complete and sign an ENERGY STAR Homes Northwest Program Single-Family Builder Agreement and provide an IRS form W-9 to the Company. In order to receive a financial incentive under this program, a building contractor must complete the following steps for each home:

1. Submit a completed Project Initiation Form.

2. Upon the completion of construction, provide documentation that verifies a State Certifying Organization (SCO) registered with the Alliance has certified the home. Documentation from the SCO must include verification that the home has been constructed to the ENERGY STAR Homes Northwest BOP specification and that the central air conditioning system has been properly commissioned by a certified heating and cooling systems technician.

SCHEDULE 78
RESIDENTIAL ENERGY CONSERVATION
PROGRAM

AVAILABILITY

This schedule is available throughout the Company's service area within the State of Oregon to residential Customers who qualify for the Residential Energy Conservation Program.

DEFINITIONS

Cash Payment means a payment made by the Company to the dwelling owner or to the contractor on behalf of the dwelling owner for energy conservation measures.

Commission means the Oregon Public Utility Commission.

Cost-Effective means that an energy conservation measure that provides or saves a specific amount of energy during it's life cycle results in the lowest present value of delivered energy costs of any available alternative. However, the present value of the delivered energy costs of an energy conservation measure shall not be treated as greater than that of a non-conservation energy resource or facility unless that cost is greater than 110 percent of the present value of the delivered energy cost of the non-conservation energy resource or facility.

Dwelling means real or personal property within the state inhabited as the principal residence of a dwelling owner or a tenant including a mobile home, a floating home and a single unit in multiple-unit residential housing, but not a recreational vehicle.

Dwelling Owner means the person who has legal title to a dwelling, including the mortgagor under a duly recorded mortgage of real property, the trustor under a duly recorded deed of trust or a purchaser under a duly recorded contract for the purchase of real property, and whose dwelling receives space heating from the Company.

Eligible Customer means any Customer receiving residential service. Responsibility for furnishing the energy audit lies within the utility providing the primary source of space heating energy. If the Company is not the primary supplier of space heating energy, it may discharge its energy audit obligation by arranging for the primary supplier of space heating energy to perform the energy audit.

Energy Audit means:

1. The measurement and analysis of the heat loss and energy utilization efficiency of a dwelling.

2. An analysis of the energy savings in mills per kWh and dollar savings potential that would result from providing energy conservation measures for the dwelling.

3. An estimate of the cost of the energy conservation measures including labor for the installation of items designed to improve the space heating and energy utilization efficiency of the dwelling and the items installed.

4. A determination of whether the energy conservation measure is cost effective.

SCHEDULE 78
RESIDENTIAL ENERGY CONSERVATION
PROGRAM
(Continued)

DEFINITIONS (Continued)

5. A preliminary assessment, including feasibility and a range of costs, of the potential and opportunity for installation of passive solar space heating and solar domestic water heating in the dwelling, and solar swimming pool heating, if applicable.

Energy Conservation Measures means measures that include the installation of items and the items installed to improve the space heating and energy utilization efficiency of a dwelling. These items include but are not limited to, caulking, weatherstripping and other infiltration preventative materials, ceiling insulation, crawl space insulation, vapor barrier materials, timed thermostats (except when used with heat pumps), insulation of heating ducts, hot water pipes and water heaters in unheated spaces, storm doors and windows and double glazed windows. Energy Conservation Measures does not include the dwelling owner's own labor.

Residential Customer means dwelling owner or tenant who is billed by the Company for electric service received at the dwelling.

Residential Space Heating Customer means a residential Customer who uses electricity as the primary source of space heating.

Space Heating means the heating of living space within a dwelling.

Tenant means a tenant as defined in ORS 91.705 or any other tenant.

NOTIFYING CUSTOMER OF PROGRAM

Upon approval by the Commission of the Company's Residential Energy Conservation Program, the Company shall promptly implement the program by sending a notice described in this section to all its Residential Customers and shall give similar notice at least once every year thereafter.

The Company will mail to a dwelling owner an offer to provide financing for Energy Conservation Measures when a tenant who is a residential space heating Customer requests that the offer be mailed to the dwelling owner, and furnishes the dwelling owner's name and address with the request.

The Notice Shall Set Forth:

1. That assistance and technical advice regarding energy conservation is available from the Company including an energy audit of a dwelling without direct charge if requested by the Residential Customer.

2. That financing for Energy Conservation Measures is available from the Company to an eligible dwelling owner in the form of a loan or cash payment.

3. That provides an address and telephone number that the Customer can call to obtain these services from the Company.

SCHEDULE 78
RESIDENTIAL ENERGY CONSERVATION
PROGRAM
(Continued)

ENERGY AUDIT

The Company will provide, within 60 days of a request by a residential space heating Customer or a dwelling owner, assistance and technical advice concerning various methods of saving energy in that Customer's or dwelling owner's dwelling, including, but not limited to an energy audit.

The energy audit shall include:

1. The measurement and analysis of the heat loss and energy utilization efficiency of a dwelling.

2. An analysis of the energy savings in mills per kWh and dollar savings potential that could result from providing Energy Conservation Measures for the dwelling.

3. An estimate of the cost of the Energy Conservation Measures including labor for the installation of items designed to improve the space heating and energy utilization efficiency of the dwelling excluding the dwelling owner's own labor, and the items installed.

4. A determination of whether the Energy Conservation Measure is cost-effective.

5. A preliminary assessment, including feasibility and a range of costs, of the potential and opportunity for installation of passive solar space heating and solar domestic water heating in the dwelling and solar swimming pool heating, if applicable.

If the dwelling requested to be audited is a rental unit, the audit shall include a heating cost estimate using average temperatures and typical lifestyles. A statement shall be included to the effect that a household's energy bill will contain charges for uses in addition to space heating. Such heating cost estimate and statement shall be displayed on the audit or a separate document suitable for conspicuous posting.

Upon a dwelling owner's request, the Company will provide information relative to the specific site of a dwelling with access to water resources that have hydroelectric potential, wind (which means the natural movement of air at an annual average speed of at least 8 miles an hour) and a resource area known to have geothermal space heating potential.

If sufficient data is not available to provide a valid audit based upon normal energy consumption, the Company shall make a reasonable estimate of such consumption for the purpose of completing the audit.

COST-EFFECTIVENESS GUIDELINE

"Cost-effective", as defined in Oregon Laws 1981, Chapter 778, relates an Energy Conservation Measure's cost, life cycle and the cost of alternative energy facilities.

SCHEDULE 78
RESIDENTIAL ENERGY CONSERVATION
PROGRAM
(Continued)

COST-EFFECTIVENESS GUIDELINE (Continued)

The following Energy Conservation Measures are determined to be always cost-effective:

1. Caulking

2. Weatherstripping

3. Ground cover, when installed in conjunction with under-floor insulation

4. Vapor barrier materials, when installed in conjunction with wall, ceiling, or under-floor insulation

5. Timed (set-back) thermostats (except when used with heat pumps)

6. Water heater, steam pipe, hot and cold water pipe-wraps

7. Dehumidifiers, when installed in conjunction with storm windows and doors, and caulking and weatherstripping of all openings allowing infiltration

8. Attic ventilation, excluding power ventilators, when installed in conjunction with ceiling insulation

The following Energy Conservation Measures shall be deemed to have the following life cycles:

1. Attic, ceiling, wall and under-floor insulation: 30 years

2. Insulation of walls in heated basements: 30 years

3. Insulation of heating system supply and return air ducts: 30 years

4. Thermal doors: 30 years

5. Storm windows: 15 years

6. Replacement windows meeting the requirements of Chapter 53 of the Oregon Residential Energy Code: 25 years

7. Storm doors: 7 years

COST-EFFECTIVE COMPUTATIONS

Energy Conservation Measures having an expected life cycle of 7 years shall be considered Cost-Effective if the installed cost is less than $0.44 per annual kWh saved. Energy Conservation Measures having an expected life cycle of 15 years, 25 years, and 30 years shall be considered Cost-Effective if the installed cost is less than $0.76 per annual kWh saved, $1.03 per annual kWh saved, and $1.12 per annual kWh saved, respectively.

SCHEDULE 78
RESIDENTIAL ENERGY CONSERVATION
PROGRAM
(Continued)

FINANCING

The Company will provide financing for Energy Conservation Measures at the request of a dwelling owner who occupies the dwelling as a residential space heating Customer or rents the dwelling to a tenant who is a residential space heating Customer if the dwelling has an electrical space heating system, installed and operational, which is designed to heat the living space of the dwelling. The financing program shall give the eligible dwelling owner a choice between a cash payment or a loan. As a condition of eligibility for either a cash payment or a loan, an Energy Audit of the dwelling will be required in order to determine which Energy Conservation Measures are Cost-Effective.

The Company will offer to all qualifying owners a choice between the following levels of assistance:

COST EFFECTIVE MEASURES

1. A loan by the Company not to exceed $5,000, upon approved credit, to be used to pay for the Energy Conservation Measures over a period of time not to exceed 10 years. Minimum monthly payment will be $15. Interest will be paid at a 6½ percent annual rate for the cost of those measures, or a portion of the cost thereof, which are in accordance with the Cost-Effectiveness criteria of this schedule; or

2. A cash payment to the dwelling owner for 25 percent of the Cost-Effective portion of the Energy Conservation Measures recommended, including installation (but not including the dwelling owner's own labor), not to exceed the cost of the measure, up to a maximum cash payment of $1,000.

If the dwelling is a rental unit, the following additional assistance is available to qualifying dwelling owners beginning in the tax year after December 31, 1985:

1. If the loan under 1 above is selected, the dwelling owner shall be liable to repay to the utility the loan amount minus the present value of the tax credits to Idaho Power established pursuant to ORS 469.185 to 469.225; or

2. If the cash payment under 2 above is selected, the cash payment shall be supplemented by an amount equal to the present value of the tax credits to Idaho Power established pursuant to ORS 469.185 to 469.225.

NON COST EFFECTIVE MEASURES

1. A loan arranged or issued by the Company for the non Cost-Effective portion of Energy Conservation Measures not to exceed the difference between $5,000 and the amount loaned under paragraph 1 above. Measures over a period of time not to exceed 10 years. Interest will be paid at the annual rate established by the Public Utility Commission of Oregon and the minimum monthly payment will be $15.

SCHEDULE 78
RESIDENTIAL ENERGY CONSERVATION
PROGRAM
(Continued)

FINANCING (Continued)

An eligible dwelling owner may obtain up to $5,000 in loans or $1,000 in cash payments for each dwelling. For any dwelling, whenever the combined interest rate computed for both Cost-Effective and Non Cost-Effective measures financed under this schedule exceeds 12 percent, the interest rate for the loan financing the Non Cost-Effective measures shall be recomputed so that the combined rate for the two loans equals 12 percent.

A dwelling owner who acquires a dwelling for which a previous loan was obtained under the program may obtain a loan or cash payment for Energy Conservation Measures for the newly acquired dwelling under circumstances including, but not necessarily limited to, when (a) the new dwelling owner chooses the same financing option chosen by the previous dwelling owner who obtained financing under this program; and (b) there remain Cost-Effective Energy Conservation Measures to be undertaken with regard to the dwelling. Provided, however, there may be no more than two loans or cash payment for each dwelling.

No cash payment shall be allowed or paid for the cost of Energy Conservation Measures provided more than one year before the date of the application for payment.

The Company shall charge or bill a dwelling owner on the periodic utility bill for the loan repayment of those Energy Conservation Measures installed.

A dwelling owner served by the Company who applies for financing of Energy Conservation Measures, may use an Energy Audit obtained from the Company under Oregon Laws, 1977, Chapter 889, before November 1, 1981, without obtaining a new energy audit.

Energy Conservation Measures installed in conjunction with construction of a new dwelling or construction which increases or otherwise changes the living space in the dwelling such as an addition, substantial alteration or remodeling, shall not be financed under the financing program.

CREDIT APPLICATIONS AND SECURITY FOR LOANS

Dwelling owners who desire loan financing will complete and sign a credit application. The Company will investigate credit applications in-house or through commercial credit rating bureaus and shall approve or reject applications. If credit is approved by the Company, the dwelling owner shall sign a promissory note in an amount not to exceed the cost of the Energy Conservation Measures, which promissory note shall bear interest at the rate or rates specified above. The Company will prepare and provide all documents necessary to complete financing arrangements.

OTHER SERVICES

The Company shall verify through post-installation inspections that Energy Conservation Measures financed by the Company are installed in a workmanlike manner.

The Company shall not disburse any funds used for principal payment until such post-installation inspections have been completed.

SCHEDULE 79
WEATHERIZATION ASSISTANCE FOR QUALIFIED CUSTOMERS PROGRAM

AVAILABILITY

Service under this schedule is available to agencies throughout the Company's service area within the State of Oregon participating in the Low Income Weatherization Assistance Program administered by the Oregon Housing & Community Services Department. Service under this schedule is subject to the provisions of the signed Agreement between the agency and the Company.

APPLICABILITY

Service under this schedule is applicable to qualifying energy conservation measures installed in single- and multi-family residential dwellings, including mobile homes, which have permanently wired electric space heating of 5 watts or more per square foot. Service is also applicable to qualifying energy conservation measures installed in buildings which have permanently wired electric space heating of 5 watts or more per square foot, which are occupied by private, non-profit organizations which serve primarily low-income clientele, and which have obtained a 501(c)(3) tax exempt status. Energy conservation measures installed must meet the qualifying specifications of the Low Income Weatherization Assistance Program administered by the Oregon Housing and Community Services Department. Qualifying energy conservation measures are those specified in the Low Income Weatherization Assistance Plan, except that repair or replacement of fossil fuel furnaces and installation of plastic window coverings do not qualify under this schedule.

GRANTS TO AGENCIES

The Company will determine the amount of annual grant funds available to each participating agency each year in accordance with the provisions of the Agreement. Funds will be distributed to a participating agency upon demonstration by the agency that qualifying conservation measures have been installed in a dwelling. Grant funds made available to an agency but not distributed to that agency during the current year may be carried forward to the next year.

The Company grant funds may be used to fund up to 85 percent of the total cost of qualifying conservation measures installed in a dwelling provided at least 15 percent of the total cost of qualifying conservation measures is funded by the Department of Energy.

Non-Profit 501(c)(3) Buildings: The Company will make funds available for the installation of weatherization measures in qualifying non-profit 501(c)(3) buildings in accordance with the provisions of the Agreement. The Company funds may be used to fund up to 100 percent of the total cost of qualifying conservation measures.

In addition to weatherization funds, the Company will provide to each agency an administrative payment equal to 10 percent of the portion funded by the Company for each dwelling or building for which weatherization was completed with the assistance of Company funds.

SCHEDULE 80
EASY UPGRADES PROGRAM

AVAILABILITY

Service under this schedule is available to commercial and industrial Customers throughout the Company's service area within the State of Oregon taking service under Schedule 7, Schedule 9, or Schedule 19.

APPLICABILITY

This schedule is applicable to electric energy efficiency retrofit projects typical of commercial or industrial applications that meet the requirements of the Easy Upgrades Program.

PROGRAM DESCRIPTION

The Easy Upgrades Program is an incentive-based program designed to help cover a portion of the costs of installing energy efficiency features into existing commercial and industrial buildings. The Easy Upgrades Program uses a prescriptive approach to provide incentives for six general energy efficiency project categories: lighting and lighting controls, heating ventilation and air conditioning (HVAC) systems, motors and motor controls, building shell, plugs loads, and retail display refrigeration.

DEFINITIONS

British Thermal Unit. A measure of energy, referred to as BTU, which allows comparisons of disparate buildings, equipment types and/or fuel sources. As BTU/hour (BTUH) it refers to the energy over time which becomes the basis for equipment sizing and efficiency measurements.

Case. Refrigerated display case typically found in grocery stores. Refrigeration cases can be low temperature (for frozen products) or medium temperature (for refrigerated products). Cases can be open upright, enclosed by glass doors, or coffin cases that are open on the top.

Delamping. The permanent removal of fluorescent lamps during a lighting retrofit project. This can be achieved by a one-for-one retrofit where the installed fixture has fewer lamps than were previously in place. Delamping can also be achieved through a retrofit project that replaces old fixtures on a less than one-for-one basis.

Economizer. A feature of air conditioning units that relies on the "free cooling" effect of outside air during the cooler part of the year and/or day to minimize the need for the compressor's operation to generate mechanical cooling.

Energy Management System. A control technology that uses a series of sensors and computer logic to manage the energy use of an entire building or some subset of the building including, but not limited to, the HVAC system, lighting, and commercial or industrial refrigeration.

SCHEDULE 80
EASY UPGRADES PROGRAM
(Continued)

DEFINITIONS (Continued)

Fixture. An integral lighting system that consists of the lamp(s), ballast(s), and the housing that results in a self-contained source of illumination when supplied with electricity.

HVAC System. The equipment that provides a building's heating, ventilation, and air conditioning. HVAC equipment includes air conditioning units, boilers, chillers, cooling towers, furnaces, heat pumps, and other related components.

Incentive. Financial payment provided by Idaho Power to program participants to help cover a portion of the costs of installing or implementing energy efficiency measures.

Measure. Energy efficient features including, but not limited to, replacement equipment, added building materials, control features, systems or processes.

Occupancy Sensor. A technology used to sense the presence of people in an area and control lighting, setback thermostat settings, or even plug loads according to the areas occupancy status. The occupancy sensor turns on controlled equipment when it senses that people are present and turns off equipment when the presence of people is not sensed resulting in electricity savings.

Retrofit. The replacement of existing building materials or equipment, or the addition of controls or other devices through measures that increase the efficiency of building systems or processes.

Site. A single location taking electric service at one or more metered service points.

Ton. The measure of the output of cooling equipment for air conditioning or refrigeration. A ton of cooling capacity is equal to 12,000 BTUH.

INCENTIVE STRUCTURE

To be eligible for an incentive, installation of the qualifying equipment cannot have started prior to May 1, 2007. Installed measures must meet the requirements of the Easy Upgrades Program as detailed in Tables 1 through 6. Incentives will not be paid for measures required by Oregon code, mandated by federal standards, or otherwise required. Incentive payments will not exceed 100% of the installed cost for any specified measure. Eligible projects are subject to a maximum incentive cap of $100,000 per site per year.

SCHEDULE 80
EASY UPGRADES PROGRAM
(Continued)

INCENTIVE STRUCTURE (Continued)

TABLE 1: LIGHTING AND LIGHTING CONTROLS

Equipment category	Installing	Replacing	Incentive Per Unit	Notes
T8 Fluorescents	1- or 2-lamp 4' T8 fixture	1- or 2-lamp 4' T12 fixture	$14.00	1
	3-lamp 4' T8 fixture	3-lamp 4' T12 fixture	$24.00	1
	4-lamp 4' T8 fixture	4-lamp 4' T12 fixture	$32.00	1
	2-lamp 8' T8 fixture	2-lamp 8' T12 fixture	$26.00	1
	2-lamp 8' T8 HO fixture	2-lamp 8' T12 HO fixture	$46.00	1, 2
	4-lamp 4' T8 High Bay fixture	Fixture drawing 250W or more	$80.00	1
	6-lamp 4' T8 High Bay fixture	Fixture drawing 400W or more	$120.00	1
	8-lamp 4' T8 High Bay fixture	Fixture drawing 750W or more	$190.00	1
	Low wattage T8 lamps	Standard wattage T8 lamps	$0.50	9
T5 Fluorescents	1- or 2-lamp 4' T5 fixture	1- or 2-lamp 4' T12 fixture	$14.00	1
	3-lamp 4' T5 fixture	3-lamp 4' T12 fixture	$24.00	1
	4-lamp 4' T5 fixture	4-lamp 4' T12 fixture	$30.00	1
	2-lamp 4' T5 HO fixture	4-lamp 4' T12 fixture	$28.00	1, 2
	3-lamp 4' T5 HO fixture	Fixture drawing 250W or more	$50.00	1, 2
	4-lamp 4' T5 HO fixture	Fixture drawing 400W or more	$90.00	1, 2
	6-lamp 4' T5 HO fixture	Fixture drawing 400W or more	$60.00	1, 2
Fluorescent Delamping	Delamping fixtures	In a T12 fixture to T8 or T5 retrofit	$12.00	1, 3
Metal Halide (MH) Lighting	30-70W efficient MH fixture	Fixture drawing at least 20W more	$18.00	1, 4
	70-150W efficient MH fixture	Fixture drawing at least 25W more	$22.00	1, 4
	150-250W efficient MH fixture	Fixture drawing at least 40W more	$26.00	1, 4
	250-360W efficient MH fixture	Fixture drawing at least 80W more	$55.00	1, 4
	360-500W efficient MH fixture	Fixture drawing at least 120W more	$75.00	1, 4
	500W+ efficient MH fixture	Fixture drawing at least 200W more	$105.00	1, 4
Lighting Controls	Occupancy sensor, wall/ceiling	Manual light switch	$40.00	
	Photocell dimming control	No prior control	$40.00	4
	Integral occupancy sensor	Manual switches or no control	$0.10	5
	Auto-off time switch	Controlling 100W or more	$20.00	
	Time clock control	No prior control	$20.00	
Compact Fluorescents (CFL) or Light Emitting Diodes (LEDs)	Screw-in lamp (25W or less)	Fixture drawing 40W or more	$2.00	6, 10
	Screw-in lamp (over 25W)	Fixture drawing 100W or more	$4.00	6, 10
	CFL or LED hardwired fixture	Incandescent or other fixture	$15.00	6, 10
Sign Lighting	LED or equivalent exit sign	Incandescent or fluorescent exit sign	$15.00	
	LED or equivalent exit sign	Marquee/Sign lighting	$15.00	7
Holiday Lights	LED lights	Incandescent T1¾ "mini" Incandescent C7 or 9	$0.10 $0.30	8

SCHEDULE 80
EASY UPGRADES PROGRAM
(Continued)

INCENTIVE STRUCTURE (Continued)

Table 1 Notes:

1) Incentive amount is based on energy-saving projections assuming lighting operation of 3,000 hours per year.

2) HO refers to high output fluorescent lighting fixtures.

3) The fluorescent delamping incentive is additive to the applicable lighting retrofit incentive. The T8 and T5 retrofits incentives are based on a lamp for lamp replacement. The delamping "bonus" also applies when the number of lamps installed is less than the number removed.

4) Applicable lighting systems are limited to building-connected fixtures. Non building-connected lighting, such as area or parking lot light fixtures, are not eligible.

5) Integral occupancy sensor incentive is based on the building floor area, in square feet, lit by the controlled lighting system.

6) Any CFL receiving a retail buy-down financed in whole or in part by Idaho Power are not eligible.

7) Marquee/sign lighting incentive is based on the sign dimensions, in square feet, of the sign retrofit.

8) Incentives will be paid per incandescent bulb retired, not to exceed the total price paid for new LED replacement bulbs. LED bulbs must replace holiday lights that are powered by a metered service connection.

9) Low-wattage T8 lamps are those with a nominal lamp wattage of 30W or less. This incentive applies as an adder when these lamps are installed as part of a T12 to T8 system retrofit. It can also apply to existing T8 systems that are relamped with low-wattage T8s.

10) LED screw-in lamps or hardwired fixtures are treated the same as CFLs for these incentives.

SCHEDULE 80
EASY UPGRADES PROGRAM
(Continued)

INCENTIVE STRUCTURE (Continued)

TABLE 2: HVAC AND HVAC CONTROLS

Equipment category	Installing	Replacing	Incentive Per Unit	Notes
Air Conditioning (AC) Units	PTAC/PTHP unit, min 12 EER	Standard PTAC/PTHP unit	$50.00	7
	5 ton or less 1 phase unit, ≥ 14 SEER	Standard (std.)1-5 ton AC unit	$25.00	1
	5 ton or less 1 phase unit, ≥ 15 SEER	Std. 5 ton or less AC unit	$50.00	
	5 ton or less 1 phase unit, ≥ 16 SEER	Std. 5 ton or less AC unit	$75.00	
	5 ton or less 3 phase unit, ≥ 13 SEER	Std. 1-5 ton AC unit	$50.00	2
	5 ton or less 3 phase unit, ≥ 14 SEER	Std. 5 ton or less AC unit	$75.00	
	5 ton or less 3 phase unit, ≥ 15 SEER	Std. 5 ton or less AC unit	$100.00	
	6 - 10 ton AC unit, ≥ 11 EER	Std. 6 – 10 ton AC unit	$50.00	2
	11 - 19 ton AC unit, ≥ 10.8 EER	Std. 11 - 19 ton AC unit	$50.00	2
	20 ton or more AC unit, ≥ 10 EER	Std. 20 ton+ AC unit	$50.00	2
Economizers	Air side economizer control addition	No prior control	$75.00	
	Water side economizer control addition	No prior control	$75.00	
	Air side economizer control repair	Non-functional economizer	$250.00	3
Evaporative Coolers/Pre-Coolers	Pre-cooler added to condenser	Standard air cooled AC unit	$100.00	
	Retrofit to direct evaporative cooler	Replacing std. AC unit	$200.00	
	Retrofit to indirect evaporative cooler	Replacing std. AC unit	$300.00	
Variable Speed Fans/Pumps	Variable speed drive (VSD), fan	Single speed HVAC sys fan	$60.00	4
	Variable speed drive, pump	Single speed HVAC sys pump	$60.00	4
Programmable Thermostats	7-day, two-stage setback thermostat	Manual thermostat	$40.00	5
Automated Control Systems	Energy management control system	Manual controls	$0.30	6
	Control system reprogramming	Automated control system	$0.10	8
	Lodging room occupancy controls	Manual controls	$50.00	9

SCHEDULE 80
EASY UPGRADES PROGRAM
(Continued)

INCENTIVE STRUCTURE (Continued)

Table 2 Notes:

1) Qualifying efficiencies are based on specifications established by the Consortium for Energy Efficiency (CEE) in Tier 2 of the High Efficiency Commercial Air Conditioning and Heat Pump Initiative (HECAC) specifications.

2) Qualifying efficiencies are based on specifications established by the Consortium for Energy Efficiency (CEE) in Tier 1 of the High Efficiency Commercial Air Conditioning and Heat Pump Initiative (HECAC) specifications.

3) Economizer repair incentives are one-time and require an itemized invoice and documentation of repairs made. The per-unit incentive can not exceed the stated cost on the invoice.

4) VSD installations only apply to variably loaded fan and pump motors operating at least 2,000 hours per year. VSDs must be installed in accordance with Institute of Electrical and Electronics Engineers (IEEE) Standard 519.

5) Programmable thermostats must be commercial-grade, two-stage models with 7-day programmability and battery back-up. Three stage models are recommended when installed to control heat pump operation. Optimum start capabilities are also recommended.

6) Automated EMS control incentives are based on the building floor area, in square feet, of the HVAC system(s) controlled and are limited to $10,000 per site.

7) Packaged Terminal Air Conditioning (PTAC) and Packaged Terminal Heat Pump (PTHP) units are through-the-wall units of 15,000 BTUH cooling output or less, commonly used in lodging rooms.

8) Automated control system reprogramming to optimize energy performance are one-time and require itemized documentation of the programming changes made. The per-site incentive is limited to $2,500 and can not exceed the stated cost on the invoice.

9) Lodging room occupancy controls apply to any smart system that can sense when the room is unoccupied and turns the room HVAC unit off or adjusts accordingly.

SCHEDULE 80
EASY UPGRADES PROGRAM
(Continued)

INCENTIVE STRUCTURE (Continued)

TABLE 3: MOTORS AND MOTOR CONTROLS				
Equipment category	Installing	Replacing	Incentive Per Unit	Notes
NEMA Premium Efficiency™ Motors	1 HP Motor, minimum 85.5% efficiency	Equal or larger size std. motor	$20.00	1
	1.5 HP Motor, minimum 86.5% efficiency	Equal or larger size std. motor	$25.00	1
	2 HP Motor, minimum 86.5% efficiency	Equal or larger size std. motor	$30.00	1
	3 HP Motor, minimum 89.5% efficiency	Equal or larger size std. motor	$35.00	1
	5 HP Motor, minimum 89.5% efficiency	Equal or larger size std. motor	$40.00	1
	7.5 HP Motor, minimum 91.7% efficiency	Equal or larger size std. motor	$55.00	1
	10 HP Motor, minimum 91.7% efficiency	Equal or larger size std. motor	$70.00	1
	15 HP Motor, minimum 93.0% efficiency	Equal or larger size std. motor	$90.00	1
	20 HP Motor, minimum 93.0% efficiency	Equal or larger size std. motor	$110.00	1
	25 HP Motor, minimum 93.6% efficiency	Equal or larger size std. motor	$130.00	1
	30 HP Motor, minimum 94.1% efficiency	Equal or larger size std. motor	$150.00	1
	40 HP Motor, minimum 94.1% efficiency	Equal or larger size std. motor	$180.00	1
	50 HP Motor, minimum 94.5% efficiency	Equal or larger size std. motor	$220.00	1
	60 HP Motor, minimum 95.0% efficiency	Equal or larger size std. motor	$280.00	1
	75 HP Motor, minimum 95.4% efficiency	Equal or larger size std. motor	$350.00	1
	100 HP Motor, minimum 95.4% efficiency	Equal or larger size std. motor	$420.00	1
	125 HP Motor, minimum 95.4% efficiency	Equal or larger size std. motor	$550.00	1
	150 HP Motor, minimum 95.8% efficiency	Equal or larger size std. motor	$650.00	1
	200 HP Motor, minimum 96.2% efficiency	Equal or larger size std. motor	$750.00	1
Downsizing Bonus	For downsizing motors during retrofit	10-200HP existing motor	$3.00	2
ECM Motors	Electronically Commutated Motor (ECM)	Standard Motor	$30.00	
Variable Speed Controls	Variable Speed Drives	100 HP Motor or less	$60.00	3

SCHEDULE 80
EASY UPGRADES PROGRAM
(Continued)

INCENTIVE STRUCTURE (Continued)

Table 3 Notes:

1) Any 1,800 rpm Open Drip Proof (ODP) or Totally Enclosed Fan Cooled (TEFC) that meet the NEMA Premium™ nominal full-load efficiency ratings are eligible. 1,200 and 3,600 rpm motors may be eligible based on a different efficiency rating. Refer to the applicable NEMA Premium™ nominal full-load efficiency ratings to determine eligibility. Motors must have a minimum expected run time of 2,000 hours per year to be eligible.

2) The motor downsizing bonus is additive to the applicable motor retrofit incentive. The motor retrofit incentives are based on a same size replacement. The downsizing bonus applies when the size of the motor installed is less than the one removed.

3) VSD installations only apply to variably loaded motors operating at least 2,000 hours per year. VSDs must be installed in accordance with IEEE Standard 519.

SCHEDULE 80
EASY UPGRADES PROGRAM
(Continued)

INCENTIVE STRUCTURE (Continued)

TABLE 4: BUILDING SHELL				
Equipment category	Installing	Replacing	Incentive Per Unit	Notes
Premium Windows	Low U-value, SHGC, High VLT	Standard windows	$1.00	1, 2, 4
Efficient Windows	Low U-value, SHGC	Standard windows	$0.50	1, 2, 4
Window Shading	Adding window shade film	No film or other shading	$0.50	2, 4
	Adding window shade screen	No screen or other shading	$0.50	2, 4
Roll-Up Doors	Insulated door (min R4)	Uninsulated roll-up door	$0.05	5
	High-speed automatic door	Standard automatic door	$25.00	6
Reflective Roofing	Adding reflective roof treatment	Non-reflective low pitch roof	$0.05	2, 3, 4
Roof/Ceiling Insulation	Increase to R24 min. insulation	Insulation level, R11 or less	$0.10	2, 4
	Increase to R38 min. insulation	Insulation level, R11 or less	$0.20	2, 4
Wall Insulation	Increase to R11 min. insulation	Insulation level, R5 or less	$0.05	2, 4

Table 4 Notes:

1) Premium windows must be certified by the National Fenestration Rating Council (NFRC) and meet Commercial Window Initiative (CWI) specifications for U-value, solar heat gain coefficient (SHGC), and visible light transmittance (VLT). Efficient windows meet all the same criteria with the exception of VLT.

2) Incentive eligibility is limited to installation on air conditioned buildings that utilize central air conditioning systems or packaged terminal air conditioning (PTAC) units.

3) Qualifying roof treatment must be ENERGY STAR® rated and have a total initial solar reflectivity of at least 70%.

4) Building Shell incentives are based on the surface area, in square feet, of the measure installed.

5) Insulated roll-up doors with a minimum insulation R-value of 4 are eligible when installed serving a space with central mechanical air conditioning or PTAC systems and are based on the surface area, in square feet, of the measure installed.

6) High-speed automated doors (either roll-up or folding doors) that open or close with a speed of at least 24 inches per second are eligible when installed serving a cold storage facility and are based on the surface area, in square feet, of the measure installed.

SCHEDULE 80
EASY UPGRADES PROGRAM
(Continued)

INCENTIVE STRUCTURE (Continued)

TABLE 5: PLUG LOADS

Equipment category	Installing	Replacing	Incentive Per Unit	Notes
Vending Machines	ENERGY STAR® vending machine	Standard vending machine	$75.00	1
	Beverage machine control	Vending machine with no sensor	$75.00	
	Other cold product control	Vending machine with no sensor	$50.00	
	Non-cooled snack control	Vending machine with no sensor	$25.00	
Commercial Kitchen Equipment	ENERGY STAR® dishwasher	Standard dishwasher	$15.00	2
	Low temperature dish machine	Dish machine w/ electric booster	$75.00	3
	ENERGY STAR® refrigerator	Standard residential refrigerator	$30.00	
	Solid door refrigerator, 1 door	Commercial 1 door refrigerator	$70.00	5
	Solid door refrigerator, 2 door	Commercial 2 door refrigerator	$90.00	5
	Solid door refrigerator, 3 door	Commercial 3 door refrigerator	$140.00	5
	Solid door freezer, 1 door	Commercial 1 door freezer	$100.00	5
	Solid door freezer, 2 door	Commercial 2 door freezer	$150.00	5
	Solid door freezer, 3 door	Commercial 3 door freezer	$200.00	5
	Ice maker, up to 200 lbs/day	Standard ice maker of the same size	$100.00	6
	Ice maker, 200 lbs/day +	Standard ice maker of the same size	$150.00	6
Personal Computers	80Plus PC - desktop	Standard personal computer, desktop	$5.00	
	80Plus PC - server	Standard personal computer, server	$10.00	
	ENERGY STAR® PC	Standard personal computer	$10.00	4
	ENERGY STAR® Copier	Standard copier w/out idle/off control	$25.00	
	PC network power management	No central control software in place	$10.00	
	Flat panel LCD display	Standard cathode ray (CRT) display	$10.00	
	Occupancy sensor controls	Computers, other plug loads	$10.00	
Laundry Machines	High efficiency washer	Standard washer, electric HW	$25.00	
	High efficiency coin-op washer	Coin-op wash, without electric HW	$25.00	
	High efficiency coin-op washer	Coin-op washer, with electric HW	$200.00	

SCHEDULE 80
EASY UPGRADES PROGRAM
(Continued)

INCENTIVE STRUCTURE (Continued)

Table 5 Notes:

1) Both new and rebuilt refrigerated beverage vending machines that are ENERGY STAR® certified are eligible.

2) Qualifying installations must have electric water heating and be used for at least one full cycle per work week.

3) Qualifying products must be used in a commercial kitchen or other environment where they experience at least 24 wash/rise cycles per day. Incentive payments will be based on the load (in kW) of the electric booster heater removed.

4) Qualifying PCs must meet ENERGY STAR® Version 4.0 Tier 1 specifications for desktop computers and workstations that take effect on July 20, 2007.

5) Commercial solid door refrigerators and freezers must have built-in (packaged) refrigeration systems and be listed as Tier 1 or better on the Consortium for Energy Efficiency (CEE) Commercial Kitchens Initiative list of qualifying equipment.

6) To qualify, ice makers must be included on the CEE Commercial Kitchens Initiative listing of High Efficiency Ice Machines.

SCHEDULE 80
EASY UPGRADES PROGRAM
(Continued)

INCENTIVE STRUCTURE (Continued)

TABLE 6: GROGERY REFRIGERATION				
Equipment category	Installing	Replacing	Incentive Per Unit	Notes
Refrigeration Cases	Efficient medium (med.) temperature (temp.) open case	Std. med. temp. open case	$20.00	1
	Efficient med. temp. reach-in	Std. med. temp. open case	$100.00	1
	Efficient low temp. reach-in	Std. low temp. reach-in	$150.00	1
	Efficient low temp. reach-in	Std. low temp. open case	$150.00	1
	Efficient low temp. reach-in	Std. low temp. coffin case	$55.00	1
	Vertical night covers	No covers present	$9.00	1
	Horizontal night covers	No covers present	$5.00	1
	Add refrigeration line insulation	No insulation present	$1.00	2
	Install door gasket – walk-in	No or damaged door gasket	$2.00	3
	Install door gasket – reach-in	Damaged door gasket	$1.00	3
	Install auto-closer – walk-in	No/damaged auto-closer, low temp.	$50.00	4
	Install auto-closer – reach-in	Damaged auto-closer, low temp.	$50.00	4
	Install auto-closer – walk-in	No/damaged auto-closer, med. temp.	$40.00	4
	Install auto-closer – reach-in	Damaged auto-closer, med. temp.	$40.00	4
	Install no heat glass doors	Std. low temp. reach-in	$50.00	4
	Add anti-sweat heat controls	Low/med. temp. case w/out controls	$20.00	4
Evaporator Fans	Add evaporator fan controls	Med. temp. walk-in with no controls	$25.00	5
	Install efficient evap fan motor	Med. or low temp. walk-in	$100.00	5
	Install controllable case fan motor	Standard, shaded-pole fan motors	$30.00	5
Compressors and Condensers	Efficient low temp. compressor	Standard low temp. compressor	$45.00	6
	Air cooled multiplex system	Stand alone air cooled display case	$300.00	6
	Evap cooled multiplex system	Stand alone evap cooled display case	$300.00	6
	Efficient air cooled condenser	Standard air cooled condenser	$100.00	6
	Efficient water cooled condenser	Standard air cooled condenser	$100.00	6
	Efficient evaporative condenser	Standard air cooled condenser	$200.00	6
Floating Head, Suction Pressures	Head pressure controller	Standard head pressure control	$60.00	7
	Suction pressure controller	Standard suction pressure control	$10.00	7
Case/Walk-In Lighting	T8 fluorescent lighting	T12 fluorescent lighting	$15.00	8
	LED display case lighting	T12 fluorescent lighting	$7.00	
	Fluorescent walk-in light fixture	Incandescent walk-in light fixture	$25.00	

SCHEDULE 80
EASY UPGRADES PROGRAM
(Continued)

INCENTIVE STRUCTURE (Continued)

Table 6 Notes:

1) The incentive basis for these measures is the length (in linear foot) of display cases replaced or retrofitted. The incentive will be based on the prior case length when the new case is longer than what was replaced.

2) The incentive basis for this measure is the length (in linear foot) of refrigeration line insulated.

3) The incentive basis for these measures is the length (in linear foot) of door perimeter gasketed.

4) The incentive basis for these measures is the number of doors affected.

5) The incentive basis for these measures is the number of fans or motors controlled or replaced.

6) The incentive basis for these measures is the tons of refrigeration capacity affected.

7) The incentive basis for this measure is the horsepower (HP) of compressors in the system.

8) Light Emitting Diodes (LEDs) used in refrigerated case lighting are provided an incentive based on a per-foot basis of the prior fluorescent display lighting that is removed.

SCHEDULE 81
CUSTOM EFFICIENCY
PROGRAM

AVAILABILITY

Service under this schedule is available to commercial and industrial Customers throughout the Company's service area within the State of Oregon taking service under Schedules 9 and 19. This Schedule is also available to new commercial or industrial Customers that will take service under Schedules 9 or 19 upon completion of an applicable project.

APPLICABILITY

This schedule is applicable to electric energy efficiency projects typical of commercial or industrial applications that meet the requirements of the Custom Efficiency Program.

PROGRAM DESCRIPTION

The Custom Efficiency Program is an incentive based program designed to encourage commercial and industrial Customers to install equipment, systems, or processes that increase the energy efficiency of their operations. Customers who wish to receive a financial incentive through this program are required to submit an energy efficiency project proposal for review by the Company to determine project viability and cost-effectiveness. The Custom Efficiency Program also encourages and assists commercial and industrial Customers to use electricity in an economically efficient manner through education and information, expert audits, monitoring and verification, and industrial energy efficiency demonstration projects.

QUALIFICATIONS

Project viability will be determined through a collaborative process involving the Company, a participating Customer, and if necessary, a qualified third party or the Customer's licensed Professional Engineer. Potential projects will be evaluated for program eligibility based upon the following criteria:

1. The technology must be generally accepted cost-effective energy efficiency technology. This determination will be at the Company's sole discretion.

2. Projects must not be started or equipment ordered until after the Customer has obtained written approval from the Company.

3. Projects must be completed within 12 months of the approval date unless the Customer has obtained a written extension from the Company.

SCHEDULE 81
CUSTOM EFFICIENCY
PROGRAM
(Continued)

QUALIFICATIONS (Continued)

1. Projects must exceed the current established building code requirements or standard practice for the applicable industry as determined by the Company.

2. Projects must have the potential to save a minimum of 100,000 kilowatt-hours annually. If a project does not save a minimum of 100,000 kilowatt-hours annually and no corresponding measure is available under Schedule 80 – Easy Upgrades Program, then the project may be submitted for review by the Company and, if cost effective, the project will be eligible for a financial incentive at the same rate as the Cost-Share Option.

Incentives will not be paid for measures required by Oregon code, mandated by federal standards, or otherwise required.

INCENTIVE OPTIONS

There are two incentive options available under the Custom Efficiency program; the Cost-Share option or the Self-Directed Funds option. The Cost-Share option is available to all Customers that meet the requirements of the Custom Efficiency Program. The Self-Directed Funds option is available only to Customers taking service under Schedule 19. Upon selecting an incentive option, Customers must remain committed to their selection until January 1, 2011. The maximum incentive payment will not exceed $0.12 per annual kilowatt-hour saved under either program incentive option.

Cost-Share Option. Financial incentives are determined under the Cost-Share option using the lesser of the following two calculations:

1. $0.12 per annual kilowatt-hour saved

2. 70% of total project costs

Self-Directed Funds Option. Under the Self-Directed Funds option, the Company establishes an individual account in which the Customer's contributions to the Energy Efficiency Tariff Rider are tracked. Customers selecting this option will have direct use of 100% of the funds expected to accrue within their individual account until January 1, 2011 for implementation of cost-effective DSM projects. Any individually tracked funds not utilized for a specific project by January 1, 2011 will be removed from the individual account and pooled with the rest of the Energy Efficiency Rider, Schedule 91, funds. Selection of the Self-Directed Funds option requires Customers to continue to contribute to an individual account until January 1, 2011. Customers may combine individual account funds from multiple sites to implement cost-effective DSM projects under this option.

SCHEDULE 82
COMMERCIAL ENERGY
CONSERVATION
SERVICES PROGRAM

AVAILABILITY

Service under this schedule is available throughout the Company's service area within the State of Oregon to commercial building Customers who qualify for the commercial energy conservation services program.

APPLICABLE

Service under this schedule is applicable to all commercial Customers who qualify under Senate Bill 111 or OAR 860-30-040 et seq., provided the Customer meets the provisions of service set forth herein.

DEFINITIONS

Commercial Building means a public building as defined in ORS 456.746.

Commercial Building Customer means the owner or tenant of a commercial building who is responsible for paying electricity costs of the building whether they are billed under General Service Schedules 7 or 9, or schools billed under Schedule 19, or commercial portions of industrial plants billed under other schedules.

Commercial Energy Audit means the service provided to a commercial building Customer which includes on-site data gathering, energy use analysis, and a report to the Customer recommending energy conservation measures, and an estimate of the cost/benefit of those measures.

Commercial Energy Auditor or Level I Auditor means a person who is qualified through general training and experience and who has demonstrated a general knowledge of heat transfer principals, construction terms and components, energy efficient operations and maintenance procedures, boiler and furnace efficiency improvements, infiltration controls, envelope weatherization, heating, ventilating, and air conditioning (HVAC) systems, electric control systems, lighting systems, solar insolation, and applicable energy conservation measures.

Commercial Energy Specialist or Level II Auditor means a person who is qualified through specialized training and experience, such as an engineer, architect or other specialist, who has demonstrated knowledge and abilities of a qualified commercial energy auditor, and who can in addition; (a) perform calculations of energy use analysis; (b) perform calculations of energy efficiencies of HVAC, lighting, plumbing, water, steam, control, or electrical systems; and (c) can prepare technical reports of net energy savings for energy conservation measures.

Conservation Services means those services specified in Oregon Laws 1981, Chapter 708, Sections 3(1) and 15(1)-3.

Energy Conservation Measures means conservation measures which generally require greater investment than operation and maintenance practices and typically have a payback period longer than one year. These measures include, but are not limited: (a) infiltration controls, (b) heating, ventilating, and air conditioning (HVAC) system modifications, (c) heat recovery devices, (d) envelope weatherization, (e) automatic control systems, (f) solar water heaters, (g) water heating heat pumps, (h) lighting system improvement, and (i) furnace and boiler efficiency improvement.

SCHEDULE 82
COMMERCIAL ENERGY
CONSERVATION
SERVICES PROGRAM
(Continued)

DEFINITIONS (Continued)

Operation and Maintenance Practices means practices that are presumed to be cost effective if there is little or no cost associated with the item and the simple payback period is less than one year. These practices include, but are not limited to: temperature setbacks, water flow reductions, reduced use of ancillary systems, or reduced use when a building is unoccupied, repairing air duct leaks, and steam system and furnace or boiler maintenance.

COMMERCIAL ENERGY AUDIT PROGRAM

The Company shall have available, upon request, information about energy saving operations and maintenance measures for commercial buildings. The information will be tailored to special classes of commercial building Customers.

The Company will notify annually by mail each Commercial Building Customer of the availability of information and materials about energy conservation and of Commercial Energy Audit services. New Commercial Building Customers shall be given this information and offered services at the time of application for electric service.

The Company will advise each audited Commercial Building Customer of estimated energy savings, the estimated reduction of electric service billings that would be realized during the first year, and an estimate of the cost/benefit of items recommended.

SCOPE OF THE AUDIT

When the Company receives a Commercial Energy Audit request from a Commercial Building Customer who uses an average of less than 4,000 kWh of electricity per month on a yearly basis, a qualified Company Commercial Energy Auditor will perform an onsite Commercial Energy Audit to collect data and evaluate Energy Conservation Measures including, but not limited to: (a) operations and maintenance practices, (b) simple automatic control systems, (c) envelope weatherization, (d) infiltration controls, and (e) lighting system improvements.

When the Company receives a request from a Commercial Building Customer who uses an average of more than 4,000 kWh of electricity per month on a yearly basis, the Company may use a Commercial Energy Specialist to perform a Commercial Energy Audit and evaluate more complex Energy Conservation Measures such as sophisticated automatic control systems, furnace and boiler efficiency improvements, heat recovery devices, HVAC system modifications, lighting system improvements, and solar water heaters or water heating heat pumps. The Commercial Building Customer shall be furnished an estimate of the total cost of the Commercial Energy Audit and the amount of reimbursement to be received from the Company.

Company reports to a Commercial Building Customer will include as a minimum: a brief description of the building's systems which consume energy and their overall condition; an energy use analysis; recommended operations and maintenance practices; Energy Conservation Measures including a description of each measure, and its estimated costs and dollar savings for the first year. Estimated net energy savings will be calculated. Information about the availability of state and federal tax credits and low cost financing options for the Commercial Building Customer will also be included.

SCHEDULE 82
COMMERCIAL ENERGY
CONSERVATION
SERVICES PROGRAM
(Continued)

SCOPE OF THE AUDIT (Continued)

If a Commercial Building Customer qualifies for equal or better audit services under another federal, state, or local government or utility program, the Company will refer the Commercial Building Customer to that program. Utilization of such services shall be at the option of the Customer.

FEES

There will be no charge to the Commercial Building Customer for a Commercial Energy Audit performed by a Commercial Energy Auditor. If it is necessary to utilize a commercial energy specialist to evaluate more complex Energy Conservation Measures, the Company may ask the Commercial Building Customer to participate in the costs to be incurred in performing the Commercial Energy Audit. Participation by the Commercial Building Customer in the costs to be incurred shall be in accordance with a prior, written agreement between the Commercial Building Customer and the Company. The Company will contribute toward the cost of performing the Commercial Energy Audit, an amount no less than the average amount contributed toward a Commercial Energy Audit performed by a Company Commercial Energy Auditor.

COORDINATION OF UTILITIES

Where more than one energy supplier serves a building, the Company will cooperate with other suppliers in conducting a joint analysis and preparing combined recommendations for the Customers.

If the Commercial Building Customer uses oil, wood, or a renewable resource in the building, the Company shall make reasonable efforts to determine or estimate previous energy use for that energy system, and shall evaluate the operations and maintenance aspects of the system. Where the practices and systems seem to warrant attention beyond the capability of the Commercial Energy Auditor or Specialist, the Customer shall be referred to the oil or wood supplier, qualified contractor, engineer, or architect.

RULES AND REGULATIONS

Service under this schedule is subject to the Rules and Regulations contained in the Tariff of which this schedule is a part and to those prescribed by regulatory authorities.

SCHEDULE 83
BUILDING EFFICIENCY PROGRAM

AVAILABILITY

Service under this schedule is available throughout the Company's service area within the State of Oregon to commercial building owners or developers who construct or remodel commercial buildings that will take service under the Company's Schedule 7, Schedule 9, or Schedule 19 upon completion.

APPLICABILITY

This schedule is applicable to commercial buildings scheduled to undergo new construction, expansion or major renovations. Applicable major renovations must include professional design services, substantial replacement of major building components, and be subject to review by code authorities.

PROGRAM DESCRIPTION

Building Efficiency is an incentive-based program designed to help cover a portion of the costs of designing and building energy efficiency features into commercial construction projects. Building Efficiency uses a prescriptive approach to provide incentives for specific lighting and cooling efficiency options.

INCENTIVE STRUCTURE

To be eligible for an incentive, installation of the qualifying equipment cannot have started prior to January 1, 2006. Incentives will not be paid for measures required by Oregon code, mandated by federal standards, or otherwise required. Incentive payments will not exceed 100% of the installed cost for any specified measure. Eligible projects are subject to a maximum incentive cap of $100,000 per project.

Applicable Measures		
Measure Type	Incentive	Eligibility Requirements
Premium performance windows	$1 per square foot	Premium performance windows must be certified according to the test procedures established by the National Fenestration Rating Council (NFRC) and meet the Commercial Window Initiative (CWI) minimum specifications.
High performance windows	$0.50 per square foot	High performance windows must be certified according to the test procedures established by the National Fenestration Rating Council (NFRC) and must have a U-Factor rating of 0.42 or below and a Solar Heat Gain Coefficient of 0.40 or below.
Reflective roof treatment	$0.05 per square foot of roof treatment	Reflective roof treatments must meet total initial solar reflectivity of 0.70 and an emissivity of 0.75 consistent with California's Title 24 standards for flat or minimally pitched roofs.

SCHEDULE 83
BUILDING EFFICIENCY
PROGRAM
(Continued)

INCENTIVE STRUCTURE (Continued)

Applicable Measures (Continued)		
Measure Type	Incentive	Eligibility Requirements
Air side economizer	$75 per ton of air conditioning economized	Applicable economizers must allow outdoor air capacity to meet at least 85% of an air conditioning unit's airflow rate coupled with a programmable thermostat capable of two-stage cooling controls. Limited to applications where economizers are not already required by code.
Premium efficiency air conditioning and heat pump systems	$75 per ton of air conditioning	Systems with single-phase units of 5 tons of cooling capacity or less must meet Consortium for Energy Efficiency (CEE) minimum specifications as set forth in Tier II of the High-Efficiency Commercial Air Conditioning and Heat Pumps Initiative (HECAC). All other systems must meet the CEE minimum specifications set forth in Tier I of the HECAC initiative.
Additional air conditioning unit efficiency bonus	$2.50 per ton of air conditioning for each 1/10 unit of (S)EER above the standard	Air conditioning units that exceed the HECAC Tier II standard are eligible for an additional incentive paid on the basis of the unit's cooling capacity (in tons) multiplied by each 1/10 of a point that the Seasonal Energy Efficiency Ratio (SEER) or Energy Efficiency Rating (EER) exceeds the HECAC Tier II specified minimum.
High performance complex cooling system	$250 per ton of air conditioning for each unit of COP above the standard	Complex systems without SEER or EER ratings are eligible for an incentive paid on the basis of the unit's cooling capacity (in tons) multiplied by the amount that the Coefficient of Performance (COP) exceeds the minimums specified in Table 13-O of the 2004 Oregon Structural Specialty Code.
Variable speed drives	$60 per horsepower	Variable speed controls for fans, pumps and other variably-loaded electric motors between 5 and 100 horsepower operating a minimum of 2,000 hours annually are eligible for an incentive when installed in accordance with Institute of Electrical and Electronics Engineers (IEEE) Standard 519.
Energy management control system	$0.30 per square foot of controlled space	Systems must provide automatic control of lighting, heating, cooling or other energy using systems and operate under a control schedule that results in energy savings over standard operation subject to verification by the Company.
Demand Controlled Ventilation (DCV)	$0.50 per CFM of HVAC unit airflow	DCV systems must automatically adjust ventilation rates based on occupancy levels using carbon dioxide sensors. HVAC systems must include outside ventilation capacities of at least 1,500 cubic feet per minute (CFM) and serve areas with variable occupant loading.
Reduced power density lighting system	$0.05 per square foot covered by the lighting	Lighting systems designed with a lighting power density (LPD) that is at least 10 % below the 2004 Oregon Structural Specialty Code as detailed in Table 13-G will be eligible for this incentive.

SCHEDULE 83
BUILDING EFFICIENCY
PROGRAM
(Continued)

INCENTIVE STRUCTURE (Continued)

Applicable Measures (Continued)		
Measure Type	Incentive	Eligibility Requirements
Daylighting photo controls	$0.25 per square foot of daylit space	Daylighting photo controls dim or turn off electric lights in response to levels of natural daylight. To qualify for an incentive, the design must include a consultation with the Integrated Design Lab or other qualified daylighting professional.
Occupancy sensor controls	$25 per sensor installed	Occupancy sensors are automatic switching devices that sense human occupancy and control the lighting system accordingly. Either wall- or ceiling-mounted sensors are eligible where not already required by code.
High efficiency exit signs	$7.50 per installed sign	Any code compliant exit sign that draws less than 4 watts per sign face including, but not limited to, light emitting diode (LED), cold cathode, electroluminescent, or self-luminous exit signs are eligible for an incentive.

SCHEDULE 84
CUSTOMER ENERGY
PRODUCTION NET METERING

In compliance with ORS 757.300, the Company offers net metering services to its customers in Oregon in accordance with tariffs, schedules and other regulations which are in effect in its Idaho service territory. For its Idaho service territory, the Company's Schedule 84 sets forth the provisions which govern its net metering service offering. Idaho Schedule 84 is available on the Company's Web site at www.idahopower.com.

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES

AVAILABILITY

Service under this schedule is available for power delivered to the Company's control area within the State of Oregon.

APPLICABILITY

Service under this schedule is applicable to any Seller that:

1) Owns or operates a Qualifying Facility with a Nameplate Capacity rating of 10 MW or less and desires to sell Energy generated by the Qualifying Facility to the Company in compliance with all the terms and conditions of the Standard Contract;

2) Meets all applicable requirements of the Company's Generation Interconnection Process.

For Qualifying Facilities with a Nameplate Capacity rating greater than 10 MW, a negotiated Non-Standard Contract between the Seller and the Company is required.

DEFINITIONS

Energy means the electric energy, expressed in kWh, generated by the Qualifying Facility and delivered by the Seller to the Company in accordance with the conditions of this schedule and the Standard Contract. Energy is measured net of Losses and Station Use.

Generation Interconnection Process is the Company's generation interconnection application and engineering review process developed to ensure a safe and reliable generation interconnection in compliance with all applicable regulatory requirements, Prudent Electrical Practices and national safety standards. The Generation Interconnection Process is managed by the Company's Delivery Business Unit.

Heat Rate Conversion Factor is 7,100 MMBTU divided by 1,000.

Intermittent describes a Qualifying Facility that produces electrical energy from the use of wind, solar or run of river hydro as the prime mover.

Losses are the loss of electric energy occurring as a result of the transformation and transmission of electric energy from the Qualifying Facility to the Point of Delivery.

Nameplate Capacity means the full-load electrical quantities assigned by the designer to a generator and its prime mover or other piece of electrical equipment, such as transformers and circuit breakers, under standardized conditions, expressed in amperes, kilovolt amperes, kilowatts, volts, or other appropriate units. Usually indicated on a nameplate attached to the individual machine or device.

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

DEFINITIONS (Continued)

Non-Standard Contract is a negotiated contract between any Seller that owns or operates a Qualifying Facility with a nameplate capacity rating greater than 10 MW and desires to sell Energy generated by the Qualifying Facility to the Company. The starting point for negotiation of price is the Avoided Cost Components established in this schedule and may be modified to address specific factors mandated by federal and state law, including

1) The utility's system cost data;

2) The availability of capacity or energy from a Qualifying Facility during the system daily and seasonal peak periods, including:

a. The ability of the utility to dispatch the qualifying facility;

b. The expected or demonstrated reliability of the qualifying facility;

c. The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;

d. The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;

e. The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

f. The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and

g. The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and

3) The relationship of the availability of energy or capacity from the Qualifying Facility to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a Qualifying Facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

DEFINITIONS (Continued)

Non-Standard Contract is a negotiated contract between any Seller that owns or operates a Qualifying Facility with a Nameplate Capacity rating greater than 10 MW and desires to sell Energy generated by the Qualifying Facility to the Company. The guidelines for negotiating a Non-Standard Contract are more specifically described later in this schedule in Guidelines for Negotiation of Power Purchases Agreements for Qualifying Facilities with Nameplate Capacity of 10 MW or Larger.

Point of Delivery is the location where the Company's and the Seller's electrical facilities are inter-connected or where the Company's and the Seller's host transmission provider's electrical facilities are interconnected.

Prudent Electrical Practices are those practices, methods and equipment that are commonly used in prudent electrical engineering and operations to operate electric equipment lawfully and with safety, dependability, efficiency and economy.

PURPA means the Public Utility Regulatory Policies Act of 1978.

Qualifying Facility or QF is a cogeneration facility or a small power production facility which meets the PURPA criteria for qualification set forth in Subpart B of Part 292, Subchapter K, Chapter I, Title 18, of the Code of Federal Regulations.

Seasonality Factor is the factor used in determining the seasonal purchase price of energy. The applicable factors are:

73.50% for Season 1 (March, April, May);
120.00% for Season 2 (July, August, November, December);
100.00% for Season 3 (June, September, October, January, February).

Seller is any entity that owns or operates a Qualifying Facility and desires to sell Energy to the Company.

Standard Contracts are the pro forma Energy Sales Agreements the Company maintains on file with the Public Utility Commission of Oregon for Intermittent and non-intermittent on-system Qualifying Facilities and Intermittent and non-intermittent off-system Qualifying Facilities, with a Nameplate Capacity of 10 MW or less.

Station Use is electric energy used to operate the Qualifying Facility which is auxiliary to or directly related to the generation of electricity and which, but for the generation of electricity, would not be consumed by the Seller.

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

QUALIFYING FACILITY INFORMATION INQUIRY PROCESS

There are two separate processes required for a Seller to deliver and sell energy from a Qualifying Facility to the Company. These processes may be completed separately or simultaneously.

1) Generation Interconnection Process

All generation projects physically interconnecting to the Company's electrical system, regardless of size, location or ownership, must successfully complete the Generation Interconnection Process prior to the project delivering energy to the Company. A complete description of the Small Generator Interconnection Procedures, the Interconnection Application and Company contact information is maintained on the Idaho Power website at www.idahopower.com, or Seller may contact the Company's Delivery Business Unit at 1-208-388-2658 for further information.

All generation projects delivering power under the off-system Energy Sales Agreement must successfully complete a comparable Generation Interconnection Process with the Seller's host interconnection provider and transmission provider.

2) Energy Sales Agreement

To begin the process of completing a Standard Contract or negotiating a Non-Standard Contract, for a proposed project, the Seller must submit to the Company a request for an Energy Sales Agreement. All requests will be processed in the order of receipt by the Company.

A. Communications

Unless otherwise directed by the Company, all communications to the Company regarding an Energy Sales Agreement should be directed in writing as follows:

Idaho Power Company
Cogeneration and Small Power Production
P O Box 70
Boise, Idaho 83707

B. Procedures

1. The Company's approved Energy Sales Agreement may be obtained from the Company's website at http://www.idahopower.com or if the Seller is unable to obtain it from the website, the Company will send a copy within 10 business days of a written request.

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

QUALIFYING FACILITY INFORMATION INQUIRY PROCESS (Continued)

1. In order to obtain a project specific draft Energy Sales Agreement the Seller must provide in writing to the Company, general project information required for the completion of an Energy Sales Agreement, including, but not limited to:

a) Date of request
b) Company / Organization that will be the contracting party
c) Contract notification information including name, address and telephone number
d) Verification that the Qualifying Facility meets the "Eligibility for Standard Rates and Contract" criteria
e) Copy of the Qualifying Facility's QF certificate
f) Copy of the FERC license (applicable to hydro projects only)
g) Location of the proposed project including general area and specific legal property description
h) Description of the proposed project including specific equipment models, types, sizes and configurations
i) Type of project (wind, hydro, geothermal etc)
j) Nameplate capacity of the proposed project
k) Schedule 85 pricing option selected
l) Desired term of the Energy Sales Agreement
m) Annual net energy amount
n) Maximum capacity of the Qualifying Facility
o) Estimated first energy date
p) Estimated operation date
q) Point of Delivery
r) Status of the Generation Interconnection Process

3. The Company shall provide a draft Energy Sales Agreement when all information described in Paragraph 2 above has been received in writing from the Seller. Within 15 business days following receipt of all information required in Paragraph 2, the Company will provide the Seller with a draft Energy Sales Agreement including current standard avoided cost prices and/or other optional pricing mechanisms as approved by the Oregon Public Utility Commission in this Schedule.

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

QUALIFYING FACILITY INFORMATION INQUIRY PROCESS (Continued)

4. The Company will respond within 15 business days to any written comments and proposals that the Seller provides in response to the draft Energy Sales Agreement.

5. If the Seller desires to proceed with the Energy Sales Agreement after reviewing the Company's draft Energy Sales Agreement, it may request in writing that the Company prepare a final draft Energy Sales Agreement. In connection with such request, the Seller must provide the Company with an updated status of the Generation Interconnection Process which indicates that the Seller's provided information (i.e. first energy date, operation date, etc.) are realistically attainable and any additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft Energy Sales Agreement. Once the Company has received the written request for a final draft Energy Sales Agreement and all additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft Energy Sales Agreement, the Company will provide Seller with a final draft Energy Sales Agreement within 15 business days.

6. After reviewing the final draft Energy Sales Agreement, the Seller may either prepare another set of written comments and proposals or approve the final draft Energy Sales Agreement. If the Seller prepares written comments and proposals, the Company will respond within 15 business days to those comments and proposals.

7. When both parties are in full agreement as to all terms and conditions of the final draft Energy Sales Agreement, the Company will prepare and forward to the Seller within 15 business days a final executable version of the Energy Sales Agreement. Once the Seller executes the Energy Sales Agreement and returns all copies to the Company, the Company will execute the Energy Sales Agreement. Following the Company's execution a completely executed copy will be returned to the Seller. Prices and other terms and conditions in the Energy Sales Agreement will not be final and binding until the Energy Sales Agreement has been executed by both parties.

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

AVOIDED COST COMPONENTS

The Avoided Cost Components are calculated based upon the Surrogate Avoided Resource methodology (SAR) for determining the Company's standard avoided costs.

Year	Capacity Cost (mills/kWh)	Fuel Cost (mills/kWh)
2007	25.00	60.60
2008	25.61	56.24
2009	26.22	55.61
2010	26.86	41.48
2011	27.50	41.83
2012	28.17	42.46
2013	28.85	43.87
2014	29.55	45.13
2015	30.26	46.68
2016	31.00	48.65
2017	31.75	50.83
2018	32.52	52.65
2019	33.31	55.26
2020	34.12	57.36
2021	34.95	52.80
2022	35.80	54.76
2023	36.67	57.22
2024	37.57	58.91
2025	38.48	61.16
2026	39.42	56.87
2027	40.39	59.33
2028	41.37	61.51
2029	42.39	63.83
2030	43.43	66.64
2031	44.49	67.56
2032	45.58	68.47
2033	46.70	69.46
2034	47.85	70.37
2035	49.02	71.28
2036	50.23	72.20

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

NET ENERGY PURCHASE PRICE

The Company will pay the Seller monthly, for each kWh of Energy delivered and accepted at the Point of Delivery during the preceding calendar month, in accordance with the Standard Contract, an amount determined by the Seller's choice of one of the following options:

Option 1 - Fixed Price Method

Net Energy Purchase Price =

On-peak = (Fuel Cost + Capacity Cost) X Seasonality Factor
Off-peak = Fuel Cost X Seasonality Factor

where

Fuel Cost and Capacity Cost are the Avoided Cost Components established in this schedule for the applicable calendar year of the actual Net Energy deliveries to the Company.

Option 2 – Dead Band Method

Net Energy Purchase Price =

On-peak = (AGPU + Capacity Cost) X Seasonality Factor
Off-peak = AGPU X Seasonality Factor

Actual Gas Price Used (AGPU) =
90% of Fuel Cost if
Indexed Fuel Cost is less than 90% Fuel Cost; else
110% of Fuel Cost if
Indexed Fuel Cost is greater than 110% Fuel Cost; else
Indexed Fuel Cost

where

Fuel Cost and Capacity Cost are the Avoided Cost Components established in this schedule for the applicable calendar year of the actual Net Energy deliveries to the Company, and

Indexed Fuel Cost is the applicable weighted monthly average index price of natural gas at Sumas multiplied by the Heat Rate Conversion Factor.

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

NET ENERGY PURCHASE PRICE (Continued)

Option 3 – Gas Market Method

Net Energy Purchase Price =

On-peak = (AGPU + Capacity Cost) X Seasonality Factor
Off-peak = AGPU X Seasonality Factor

Actual Gas Price Used (AGPU) = Indexed Fuel Cost

where

Capacity Cost is the Avoided Cost Component established in this schedule for the applicable calendar year of the actual Net Energy deliveries to the Company, and

Indexed Fuel Cost is the applicable weighted monthly average index price of natural gas at Sumas multiplied by the Heat Rate Conversion Factor.

MISCELLANEOUS PROVISIONS

Insurance

Qualifying Facilities with a Nameplate Capacity of 200 kilowatts or smaller are not required to provide evidence of liability insurance.

GUIDELINES FOR NEGOTIATION OF POWER PURCHASE AGREEMENTS FOR QFS WITH A NAMEPLATE CAPACITY OF 10 MW OR LARGER

1) The Company will not impose terms and conditions beyond what is standard practice. The Edison Electric Institute master agreement and the Company's Standard Contracts are useful starting points in negotiating QF agreements.

2) The Company will provide an indicative pricing proposal for a QF that plans to provide firm energy or capacity and chooses avoided cost rates calculated at the time of the obligation. The Company will provide an indicative pricing proposal within 30 days of receipt of the information the Company requires from the QF. The proposal may include other terms and conditions, tailored to the individual characteristics of the proposed project. The avoided cost rates in the indicative pricing proposal will be based on the following:

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

GUIDELINES FOR NEGOTIATION OF POWER PURCHASE AGREEMENTS FOR QFS WITH A NAMEPLATE CAPACITY OF 10 MW OR LARGER (Continued)

a. The starting point for negotiations is the avoided cost calculated under the modeling methodology approved by the Idaho Public Utilities Commission for QFs over 10 MW, as refined by the Oregon Public Utility Commission to incorporate stochastic analyses of electric and natural gas prices, loads, hydro and unplanned outages.

b. The prospective QF may request in writing that the Company prepare a draft power purchase agreement to serve as the basis for negotiations. The Company may require additional information from the QF necessary to prepare a draft agreement.

c. Within 30 days of receiving the required information, the Company will provide a draft power purchase agreement containing a comprehensive set of proposed terms and conditions.

d. The QF must submit in writing a statement of its intention to begin negotiations with the Company and may include written comments and proposals. The Company is not obligated to begin negotiations until it receives written notification from the QF. The Company will not unreasonably delay negotiations and will respond in good faith to all proposals by the QF.

e. When the parties have agreed, the Company will prepare a final version of the contract within 15 business days. A contract is not final and binding until signed by both parties.

f. At any time after 60 days from the date the QF has provided its written notification pursuant to paragraph d., the QF may file a complaint with the Oregon Public Utility Commission asking the Commission to adjudicate any unresolved contract terms and conditions.

2) QFs have the unilateral right to select a contract length of up to 20 years for a PURPA contract. The contract length selected by the QF may impact other contractual issues including, but not limited to, the avoided cost determination with respect to that QF.

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

GUIDELINES FOR NEGOTIATION OF POWER PURCHASE AGREEMENTS FOR QFS WITH A NAMEPLATE CAPACITY OF 10 MW OR LARGER (Continued)

1) The Company should consider the QF to be providing firm energy or capacity if the contract requires delivery of a specified amount of energy or capacity over a specified term and includes sanctions for non-compliance under a legally enforceable obligation. The Company shall not determine that a QF provides no capacity value simply because the Company did not select it through a competitive bidding process. For a QF providing firm energy or capacity:

a. The Company and the QF should negotiate the time periods when the QF may schedule outages and the advance notification requirement for such outages, using provisions in the Company's partial requirements tariffs as guidance.

b. The QF should be required to make best efforts to meet its capacity obligations during Company system emergencies.

c. The Company and the QF should negotiate security, default, damage and termination provisions that keep the Company and its ratepayers whole in the event the QF fails to meet obligations under the contract.

d. Delay of commercial operation should not be a cause of termination if the Company determines at the time of contract execution that it will be resource-sufficient as of the QF on-line date specified in the contract; however, damages may be appropriate.

e. Lack of natural motive force for testing to prove commercial operation should not be a cause of termination.

f. The Company should include a provision in the contract that states the Company may require a QF terminated due to its default and wishing to resume selling to the Company be subject to the terms of the original contract until its end date.

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

GUIDELINES FOR NEGOTIATION OF POWER PURCHASE AGREEMENTS FOR QFS WITH A NAMEPLATE CAPACITY OF 10 MW OR LARGER (Continued)

1) An "as available" obligation for delivery of energy, including deliveries in excess of Nameplate Capacity or the amount committed in the QF contract, should be treated as a non-firm commitment. Non-firm commitments should not be subject to minimum delivery requirements, default damages for construction delay or under-delivery, default damages for the QF choosing to terminate the contract early, or default security for these purposes.

2) For QFs unable to establish creditworthiness, the Company must at a minimum allow the QF to choose either a letter of credit or cash escrow for providing default security. When determining security requirements, the Company should take into account the risk associated with the QF based on such factors as its size and type of supply commitments.

3) When QF rates are based on avoided costs calculated at the time of delivery, the Company should use day-ahead on- and off-peak market index prices at the appropriate market hub(s).

a. For QFs providing firm energy or capacity that choose this option, avoided cost rates should be based on day-ahead market index prices for firm purchases.

b. For QFs providing energy on an "as available" basis, avoided cost rates should be based on day-ahead market index prices for non-firm purchases.

4) The Company should not make adjustments to standard avoided cost rates other than those approved by the Oregon Public Utility Commission and consistent with these guidelines.

5) The Company should make adjustments to avoided costs for reliability on an expected forward-looking basis. The Company should design QF rates to provide an incentive for the QF to achieve the contracted level and timing of energy deliveries.

6) The Company should make adjustments to avoided costs for dispatchability on a probabilistic, forward-looking basis.

7) If avoided cost rates for a QF are calculated at the time of the obligation and the Company's avoided resource is a fossil fuel plant, the Company should adjust avoided cost rates for the resource deficiency period to take into account avoided fossil fuel price risk.

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

GUIDELINES FOR NEGOTIATION OF POWER PURCHASE AGREEMENTS
FOR QFS WITH A NAMEPLATE CAPACITY OF 10 MW OR LARGER (Continued)

1) Avoided cost rates for wind QFs should be adjusted for integration cost estimates based on studies conducted for the Company's system, unless the QF contracts for integration services with a third party.

a. The Company should use the most recent integration cost data available, consistent with its evaluation of competitively bid and self-build wind resources.

b. The portion of integration costs attributable to reserves costs should be based on the difference in such costs between the wind QF and the Company proxy plant.

c. The Company should base first-year integration costs on the actual level of wind resources in the control area, plus the proposed QF. Integration costs for years two through five of the contract should be based on the expected level of wind resources in the control area each year, including the new resources the Company expects to add. Integration costs should be fixed at the year-five level, adjusted for inflation, for the remainder of the life of the wind projects in the control area.

d. The Company is prohibited from using a long-range planning target for wind resources as the basis for integration costs. However, if the Company is subject to near-term targets under a mandatory Renewable Portfolio Standard, the Company may base its integration costs on the level of renewable resources it must acquire over the next 10 years.

e. In determining integration costs, the Company should make reasonable estimates regarding the portion of renewable resources to be acquired that will be intermittent resources.

2) The Company should adjust avoided cost rates for QF line losses relative to the Company proxy plant based on a proximity-based approach.

3) The Company should evaluate whether there are potential savings due to transmission and distribution system upgrades that can be avoided or deferred as a result of the QFs location relative to the Company proxy plant and adjust avoided cost rates accordingly.

SCHEDULE 85
COGENERATION AND SMALL POWER
PRODUCTION STANDARD
CONTRACT RATES
(Continued)

GUIDELINES FOR NEGOTIATION OF POWER PURCHASE AGREEMENTS
FOR QFS WITH A NAMEPLATE CAPACITY OF 10 MW OR LARGER (Continued)

1) The Company should not adjust avoided cost rates for any distribution or transmission system upgrades needed to accept QF power. Such costs should be separately charged as part of the interconnection process.

2) The Company should not adjust avoided cost rates based on its determination of the additional cost it might incur for any debt imputation by a credit rating agency.

3) Regarding Surplus Sale and Simultaneous Purchase and Sale:

a. QFs may either contract with the Company for a "surplus sale" or for a "simultaneous purchase and sale" provided, however, that the QFs selection of either such contractual arrangement shall not be inconsistent with any retail tariff provision of the Company then in effect or any agreement between the QF and the Company;

b. The two sale/purchase arrangements described in paragraph 17. a will be available to QFs regardless of whether they qualify for standard contracts and rates or non-standard contracts and rates, however the "simultaneous purchase and sale" is not available to QFs not directly connected to the Company's electrical system;

c. The negotiation parameters and guidelines should be the same for both sale/purchase arrangements described in paragraph 17. a; and

d. The avoided cost calculations by the Company do not require adjustment solely as a result of the selection of one of the sale/purchase arrangements described in paragraph 17. a, rather than the other.

SCHEDULE 87
MANUFACTURED HOUSING
ENERGY EFFICIENCY PROGRAMS

This schedule describes the manufactured housing energy efficiency programs offered by the Company and funded by the Energy Efficiency Rider.

REBATE ADVANTAGE MANUFACTURED HOME INCENTIVES PROGRAM

AVAILABILITY

This program is available to a Customer who signs a sales agreement for a new ENERGY STAR® all-electric manufactured home. Sales of used homes or indirect sales of new homes are not eligible for this program. Applications to participate in the program are available through local manufactured home dealers. Incentives will be available on a first-come, first-served basis.

APPLICABILITY

This program is applicable to homes manufactured by an ENERGY STAR® homes manufacturer. In order to participate in the program, the home must be served under a residential electric service schedule and be sited in the Company's Oregon service territory.

SERVICE PROVIDED

Incentives are provided by the Company to Customers who purchase an eligible new all-electric manufactured home and to the sales consultant who sells the home in the following amounts:

Home Type	Customer Incentive	Sales Bonus
ENERGY STAR® qualified	$500 per eligible home	$100 per home

ENERGY HOUSE CALLS FOR MANUFACTURED HOMES PROGRAM

AVAILABILITY

This program is available to a Customer who lives in a manufactured or mobile home that is heated with an electric furnace or heat pump. The program will be effective through December 31, 2009.

APPLICABILITY

This program is applicable to Customers who own or rent a manufactured or mobile home. Renters must receive prior written approval from landlords to participate in the program. The Company shall have the sole right to determine whether the service is cost-effective. The Company also retains the right to not authorize service at homes deemed to be structurally unsound or posing other hazardous conditions.

SCHEDULE 87
MANUFACTURED HOUSING
ENERGY EFFICIENCY PROGRAMS
(Continued)

ENERGY HOUSE CALLS FOR MANUFACTURED HOMES PROGRAM (Continued)

SERVICE PROVIDED

The Customer may schedule a free Energy House Call by either contacting a Company-approved certified contractor, or positively responding to an offer from a certified contractor. The certified contractor will test the duct system for leaks. If a leak exists, the contractor will seal the leak at no charge according to regional standards outlined by the Bonneville Power Administration (BPA). In addition, program participants will receive the following free services: five compact fluorescent light bulbs, two air filters, a water heater temperature check and education information about energy efficiency.

SCHEDULE 89
SAVINGS WITH A TWIST
PROGRAM (SWAT)

This schedule describes the "Saving With A Twist Program" offered by the Company and sponsored by the Bonneville Power Administration (BPA) and coordinated by the Northwest ENERGY STAR® Con sumer Products Program.

AVAILABILITY

This program is available to customers purchasing designated compact fluorescent light (CFL) bulbs from participating retailers. Bulbs can be purchased as available on a first-come, first-served basis. The program will be effective from September 1, 2006 through December 15, 2006 or until the bulbs for the Program are exhausted, whichever is earlier.

SERVICE PROVIDED

Designated CFL bulbs range from 18-26 watts. Using BPA Conservation Rate Credit funds, the Company will pay Portland Energy Conservation, Inc. (PECI) for manufacturers' buy-down fees plus their program administration costs. The bulbs will be distributed to participating retailers to be sold for a price of $0.99-$1.29 per bulb. PECI will develop marketing and in-store point-of-purchase education materials. The Company will include its logo on selected marketing materials. PECI will also maintain a tracking database for Program managers.

SCHEDULE 91
ENERGY EFFICIENCY RIDER

APPLICABILITY

This schedule is applicable to all retail Customers served under the Company's schedules and special contracts. This Energy Efficiency Rider is designed to fund the Company's expenditures for the analysis and implementation of energy conservation and demand response programs.

MONTHLY CHARGE

The Monthly Charge is equal to the applicable Energy Efficiency Rider percentage times the sum of the monthly billed charges for the base rate components. The Monthly Charge will be separately stated on the Customer's regular billing.

Schedule	Energy Efficiency Rider
Schedule 1	1.5 %, but not to exceed $1.75 per meter per month
Schedule 7	1.5 %
Schedule 9	1.5 %
Schedule 15	1.5 %
Schedule 19	1.5 %
Schedule 24	1.5 %, but not to exceed $50.00 per meter per month
Schedule 40	1.5 %
Schedule 41	1.5 %
Schedule 42	1.5 %

SCHEDULE 92
DEPRECIATION ADJUSTMENT RIDER

PURPOSE

To recover from Customers the accelerated depreciation of the existing metering infrastructure that will be replaced by the installation of Advanced Metering Infrastructure (AMI) less the revenue requirement impact of the revised depreciation rates.

APPLICABILITY

This Schedule is applicable to all electric energy delivered to Customers served under Schedules 1, 7, 9 Secondary, and 24 Secondary.

ADJUSTMENT RATE

The Adjustment Rates, applicable for service on and after January 1, 2009, will be:

Schedule	Description	Adjustment Rate
1	Residential Service	0.0979¢ per kWh
7	Small General Service	0.0979¢ per kWh
9 Secondary	Large Power Service	0.0979¢ per kWh
24 Secondary	Irrigation Service	0.0979¢ per kWh

SPECIAL CONDITIONS

1. This Schedule will terminate within six months or less of the effective date if the Company does not commence mass deployment of meters by June 30, 2009.

2. This Schedule may be temporarily suspended in order to resolve specific issues identified during the mass deployment of meters. The Company must file an application to suspend at least 45 days before the termination deadline specified in Special Condition 1.

EXPIRATION

The Depreciation Adjustment Rider included on this Schedule will expire June 30, 2010.

SCHEDULE 95
ADJUSTMENT FOR MUNICIPAL
EXACTIONS

PURPOSE

The purpose of this schedule is to set forth the exactions such as license, privilege, franchise, business, occupation, operating, excise, sales or use of street taxes or other exactions imposed on the Company by municipal corporations and billed separately by the Company to its Customers within the corporate limits of a municipality.

APPLICABILITY

This schedule is applicable to all bills for Electric Service calculated under the Company's schedules and Special Contracts in the Company's service area within the State of Oregon as provided in Rule C of this Tariff.

ADJUSTMENT

The rates and charges for Electric Service provided under the Company's schedules will be proportionately increased by the following adjustments within the municipality on and after the effective date of the applicable municipal ordinance:

Municipality	Effective Date Of Ordinance	Adjustment Over 3.5%
City of Ontario	October 1, 1995	1.5% Franchise Tax
City of Huntington	May 29, 2003	1.0% Franchise Tax

SCHEDULE 98
RESIDENTIAL AND SMALL FARM
ENERGY CREDIT

APPLICABILITY

This schedule is applicable to the qualifying electric energy delivered to residential Customers taking service under Schedule 1, qualifying long-term care facilities taking service under Schedule 7 or Schedule 9 who are not providing full medical care to residents and where the average patient stay is 30 days or longer, and to agricultural Customers operating a water pumping or water delivery system used to irrigate agricultural crops or livestock pasturage under Schedule 24.

The Residential and Small Farm Energy Credit ("Credit") is the result of the Settlement Agreement between the Company and BPA dated October 31, 2000. The Settlement Agreement provides for the determination of benefits during the period October 1, 2001 through September 30, 2011. The Credit under this schedule is effective October 26, 2001. This schedule shall expire when the benefits derived from the Settlement Agreement for the period October 1, 2001 through September 30, 2011 have been credited to customers as provided for under this schedule.

QUALIFYING ELECTRIC ENERGY

All kWh of energy delivered during the Billing Period to residential Customers taking service under Schedule 1 and qualifying long-term care facilities taking service under Schedule 7 or Schedule 9, as described above, qualifies for the Credit under this schedule. The kWh of energy delivered during the Billing Period to applicable agricultural Customers taking service under Schedule 24 which qualifies for the Credit under this schedule is limited to either the agricultural Customer's actual metered energy or 222,000 kWh, whichever is less. Agricultural Customers will be identified by tax identification number or Social Security Number for purposes of determining qualifying electric energy under this schedule.

CREDIT ADJUSTMENT

An energy credit factor for residential Customers and qualifying long-term care facilities will be computed every twelve months. The energy credit factor is determined by dividing the sum of monthly benefit derived from the Settlement Agreement for each month of the twelve-month rate period by the sum of the projected monthly kWh of energy consumption by residential Customers and qualifying long-term care facilities. The current computation of the energy credit factor is $0.000000/kWh. A Credit equal to the current factor times the qualifying kWh of electric energy for the Billing Period will be included on each Customer billing.

An energy credit factor for applicable agricultural Customers will be computed on an annual basis by dividing the annual benefit derived from the Settlement Agreement by the qualifying kWh of electric energy billed to applicable agricultural Customers for the October through September Billing Periods. A Credit equal to the credit adjustment factor times the qualifying kWh of electric energy billed to each applicable agricultural Customer during the October through September Billing Periods will be issued to each applicable agricultural Customer in December of each year.