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IDAHO PUBLIC
UTILITIES COMMIS

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 TO ITS CUSTOMERS IN THE STATE OF IDAHO.	)	CASE NO. IPC-E-11-08

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

MICHAEL J. YOUNGBLOOD

Q. Please state your name and business address.

A. My name is Michael J. Youngblood. 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 Regulatory Affairs 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 Company.

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 Regulatory Affairs 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 Regulatory Affairs 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" or "Commission") and the Oregon Public Utility Commission ("OPUC").

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 purpose of your testimony in this matter?

A. In my testimony, I describe the overall objectives I provided Senior Regulatory Analysts, Ms. Darlene Nemnich and Mr. Scott Sparks, for the development of the Company's proposed rate design strategy for the tariff schedules. With regard to the Company's direction and future development of time variant pricing options for residential customers, I will preview the Company's plans for a new pilot to be proposed as a modification and expansion of the time variant pricing options currently offered to residential customers in the Emmett/Letha area.

For the Company's special contract customers, I will address the Company's proposed rates and rate designs for Micron Technology, Inc. ("Micron"), the J. R. Simplot Company ("Simplot"), the United States Department of Energy Idaho Operations Office ("DOE/INL"), and Hoku Materials, Inc. ("Hoku").

Lastly, I will discuss the derivation of the Fixed Cost per Customer ("FCC") and Fixed Cost per Energy ("FCE") rates to be used in determining the annual adjustment under Schedule 54, Fixed Cost Adjustment ("FCA"). The FCA discussion will culminate with the Company's proposal to remove the temporary "pilot" status of Schedule 54 and convert the FCA to an ongoing, permanent tariff schedule.

I. **RATE DESIGN OBJECTIVES**

Q. What are the Company's overall objectives with regard to its rate design strategy?

A. The Company's rate designs are developed to recover the revenue requirement targets provided by Mr. Matthew T. Larkin for each customer class and special contract customer. In doing so however, the Company continues to maintain two primary objectives with regard to rate design: (1) to establish prices that primarily reflect the costs of the services provided, and (2) to have cost-based rate proposals designed to align with and encourage energy efficiency.

Q. Is the Company proposing major rate design modifications with this filing?

A. No, the Company is not proposing major rate design changes with this filing. In the Company's last filed general rate case, Case No. IPC-E-08-10, the Commission authorized several significant rate design changes, including a three-tiered rate structure for residential customers for the summer and non-summer months, the addition of non-summer tiered rates for small general service customers, time-of-use rates for the large general service class, and the introduction of load factor pricing for the irrigation class. The Company's rate design proposals are based upon these prior changes with only minor modifications. This approach will provide the Company's customers with rate design stability and billing continuity.

Q. Because the Company is not proposing major rate design modifications in this filing, does that mean the Company is proposing to modify all billing components by the same percentage increase?

A. No. If all billing components were increased by the same uniform percentage without consideration of the cost-of-service unit costs, then some billing units would move further away from their actual unit cost of service, contrary to the Company's objective of moving toward cost-based rate designs.

Q. What rate design changes is the Company proposing with this filing?

A. For most of the Company's tariff schedules, the Company is proposing to leave the current rate design structure in place, while adjusting each of the billing components to move incrementally closer to their cost-of-service and recover the revenue assigned to each class. However, there are a few notable exceptions.

For the Schedule 1, Residential Service, the Company is proposing to retain the current three-tiered rate design. However, I have directed Ms. Nemnich to provide a residential rate design proposal that minimizes the impact of any rate change on the third-tier customers in the non-summer months.

Q. Why did you direct Ms. Nemnich to minimize the impact of any rate change on third-tier customers during the non-summer months?

A. Idaho Power continues to be a summer peaking utility with its highest system peak occurring during the summer months. It is appropriate to send a higher price signal to encourage customers to use energy more efficiently during the summer peak months. However, I directed Ms. Nemnich to minimize the impact of any rate change to third-tier customers during the non-summer months primarily in response to the lessons learned by both the Commission Staff and the Company following the implementation of the three-tier rate design in 2009.

Q. What lessons were learned following the implementation of the non-summer three-tier rate design?

A. During the winter of 2009, the Company and the Commission received record numbers of high bill complaints from customers. In response to these record numbers of complaints, both the Company and the Commission Staff independently, and together, began investigating the root causes of the complaints. There were a number of explanations for the high bill complaints, including a number of prior rate increases compounded by a record cold snap in December.

The investigation revealed that the high bill complaints were not just from the "McMansions" or large scale homes in the Treasure Valley, but from customers throughout our service territory, regardless of income, customer's age, premise type, employment class, ownership status, or size of household. In fact, the one differentiation that was significant in determining whether or not a customer was more at risk of having a high bill was whether they lived in a suburban city or a rural town.

Q. Why does living in a rural town increase a customer's risk of experiencing high electric bills?

A. In most rural settings, alternate fuels, primarily natural gas, are not readily available. The Company's all-electric customers were affected the most.

Q. Shouldn't all-electric customers who have large monthly loads, receive the higher price signal of a three tier structure in order to provide the customer with an incentive to reduce their consumption?

A. Not necessarily. In fact, many all-electric homes who heat with electricity may experience their greatest use during the winter evenings and nights, at a time when the Company's costs to serve that load are lower than during peak hours. Unlike customers who may better be able to manage their electric use during the summer months by reducing their air conditioning load during peak load, high cost times, the non-summer high-use customers may have less discretion to dramatically reduce their usage. Customers who were owners of all-electric homes felt the Company was now penalizing them for their electric use at times when production costs weren't necessarily high. Consequently, I have directed Ms. Nemnich to propose a residential rate design that would continue to send the price signals to use energy efficiently, but to minimize the rate change impact to the third tier during the non-summer months.

Q. Have you provided any other guidance for the development of the Company's tariff schedules?

A. Yes. In response to customer needs resulting from the availability of new and enhanced street lighting technologies, I directed Mr. Sparks to investigate revamping the Company's lighting schedules. As a result of his investigation, Mr. Sparks will be proposing some additional provisions and options for customers taking service under Schedule 41, Street Lighting Service. In addition, as part of the Company's annual review of its facilities charges, I have directed Mr. Sparks to update the Company's facilities charges as appropriate. The impact of these adjustments has been included in the Company's overall revenue determination.

And lastly, in preparation for an extended offering of a time variant pricing ("TVP") option, I have directed Ms. Nemnich to update our current time-of-day and critical peak pricing schedules to provide year-round TVP options to be more consistent in design with current industry standards.

II. FUTURE PLANS FOR TIME VARIENT PRICING OPTIONS

Q. What are the Company's plans to expand the time variant pricing alternatives now available to customers in Emmett and Letha?

A. Since the Company first offered a TVP option to its customers in the Emmett/Letha area on a pilot basis, the Company has anticipated that the knowledge gained from the initial pilot may one day be expanded and offered to more customers system-wide. However, there are two major projects which must be completed before TVP options can be offered across the Company's system. First, implementation of the Company's Advanced Metering Infrastructure ("AMI") smart meters must be installed in order for customers to take advantage of time variant rates. Idaho Power's three year AMI implementation project is on track to finish the meter installations by the end of 2011. Second, all of the back office infrastructure must be updated and implemented, including a new Customer Information System ("CIS") and enterprise data warehouse as described in Mr. Warren Kline's testimony. It is estimated that this work will be completed by early in the year 2013.

Q. Does this mean Idaho Power will not be able to expand its TVP offerings until mid 2013?

A. No. Idaho Power anticipates offering the TVP options as an expanded pilot to additional customers outside of the Emmett Valley next year. It is indeed in anticipation of such an expanded offering that the Company is making the changes to the current Schedules 4 and 5 with this filing.

Q. How does the Company propose to transition the customers who are currently taking service under the Company's Schedule 4, Energy Watch and Schedule 5, Time-of-Day pricing options?

A. The Company's proposal is for the customers who are currently taking service under the existing Schedules 4 and 5 be moved to Schedule 1 following the 2011 summer season. Schedules 4 and 5 rates and rate structures for the non-summer months are identical to that of Schedule 1, therefore the customers' bills would not be adversely affected in any way. Prior to the summer season of 2012, the Emmett customers will have the opportunity to fully evaluate the revised TVP rate structures, and will be able to move back to a time-of-day or critical peak pricing option if they so desire. Company representatives will be available to assist the customers in understanding the new pricing structure and answer any questions they may have.

Q. Why is the Company proposing these changes now to the Energy Watch and Time-of-Day pricing options?

A. Idaho Power envisions the proposed Schedules 4 and 5 to be the foundational time variant pricing options that will be offered to residential customers when an expanded pilot is rolled out. With these changes in place, the Company anticipates offering TVP options to a greater number of participants as an expanded pilot in 2012. The Company anticipates making a separate filing prior to that time explaining the details of the proposed pilot. While the pilot would be expanded from the current geographical limit of the Emmett Valley, it would still be limited in numbers pending the completion of the implementation of the required infrastructure needed to support a larger offering.

III. SPECIAL CONTRACT CUSTOMERS

Q. What are the Company's rate design proposals for the Special Contract customers?

A. The Company is proposing to maintain the current rate structures for the Special Contract customers of Micron, Simplot, and Hoku. Accordingly, the existing rates for the Special Contract customers Micron and Simplot are simply increased uniformly by 14.85 percent to recover the revenue requirement shown on Mr. Larkin's Exhibit No. 38. The Company's proposed rates for each of the Special Contract customers are shown in Exhibit No. 43.

For Hoku, consistent with its current contract, the First Block Contract Demand Charge and Energy Charge are fixed and not subject to change. The Second Block Charges increase or decrease uniformly with any base rate change authorized by the Commission that is applicable to Idaho Power's Tariff Schedule 19T customers. Consequently, Idaho Power proposes that Hoku's Second Block Demand and Energy Charges be increased by 14.84 percent, consistent with Schedule 19T.

The Company and the DOE/INL, at the time of this filing, are negotiating a new special contract. On March 9, 2011, the Commission issued Order No. 32199 in Case No. IPC-E-11-02 approving a 120-day extension continuing the existing contract until September 14, 2011. In anticipation that a special contract with DOE/INL will be completed and approved by this Commission by September 14, 2011, the Company has developed rates for the DOE to recover $8,799,100, as shown on Mr. Larkin's Exhibit No. 38. This represents a 14.85 percent increase over current rates. However, contract negotiations are still ongoing, and Idaho Power has not yet finalized a specific rate design for DOE/INL. Regardless of the final rate design, the amount of revenue required from DOE/INL will not be different from that proposed in this case. Once a new rate design is finalized for the DOE/INL contract, the parties will submit the new design as the final rate design in this case.

IV. FIXED COST ADJUSTMENT

Q. Please describe the Fixed Cost Adjustment ("FCA") mechanism.

A. The FCA is a rate mechanism that is designed to remove the financial disincentive to utility acquisition of demand-side management resources. The mechanism accomplishes this goal by severing the link between energy sales and the recovery of fixed costs. Currently, the FCA applies only to Residential Service (Schedules 1, 3, 4, and 5) and Small General Service (Schedule 7). The annual FCA amount is determined according to the following formula:

FCA = (CUST X FCC) - (NORM X FCE)

Where:

FCA = Fixed Cost Adjustment;

CUST = Actual number of customers, by class;

FCC = Fixed Cost per Customer, by class;

NORM = Weather-normalized energy, by class;

FCE = Fixed Cost per Energy, by class.

Q. What values are required to calculate the FCA amount annually?

A. As outlined in the above formula, for each class (Residential Service and Small General Service), the actual number of customers ("CUST"), the fixed cost per customer ("FCC"), weather-normalized energy ("NORM"), and the Fixed Cost per Energy ("FCE") are required to determine the FCA amount. Two of these variables (CUST and NORM) are determined at the end of each year based upon the Company's actual billing records. The other two variables (FCC and FCE) are updated each time the Company files a general rate case and are based on the results of the class cost-of-service study.

Q. Have you updated the FCC and FCE rates as part of this general rate case proceeding?

A. Yes. Pursuant to Order No. 30267, I have updated the FCC and the FCE rates using the functionalized and classified revenue requirement data provided by Mr. Larkin. The updated FCC and FCE rates have been included on the revised Schedule 54, Fixed Cost Adjustment.

Q. Please describe the process used to determine the FCC and FCE rates for the FCA mechanism, which have been submitted as part of this general rate case proceeding.

A. The FCC and FCE rates submitted as part of this general rate case proceeding are based upon the 2011 test year. These rates most accurately represent the Company's current fixed costs. Exhibit No. 44, Tables I, II, and III detail the computational process that was used to determine these class-specific fixed-cost amounts.

The first step in this process is a determination of the 2011 test year fixed cost recovery embedded in the energy charges for Residential Service and Small General Service customers. As can be seen on Exhibit No. 44, Table III, column J, for Residential Service, $269,822,080 of fixed costs is to be recovered from the residential customers through energy charges. For Small General Service, $11,206,634 of fixed costs is to be recovered from the energy charges.

Q. Do these fixed cost amounts for the Residential and Small General Service customer classes include more than their actual class cost of service?

A. Yes. There is a difference between the class cost of service numbers and the amount of requested revenue requirement. This difference is a result of the cross-class subsidies that are currently present in the Company's rate structure. The total cross-class subsidies as well as the fixed cost portion of those subsidies are identified on Exhibit No. 44, Table II.

Q. Why is it important to include these fixed cost subsidies for the Residential and Small General Service classes?

A. When fixed costs are recovered through a volumetric rate, the effects of any conservation program that reduces energy consumption results in a loss in the recovery of those fixed costs. In the case of both the Residential and Small General Service customer classes, the reduction of energy consumption through conservation measures not only prevents the Company from recovering the fixed costs associated with those classes, but in addition, prevents the fixed cost recovery of the subsidies which are incorporated in their energy rates.

Q. How are the class-specific fixed cost amounts established in the initial step used to derive the updated FCC rates?

A. The determination of the FCC rate utilizes the annual average number of customers for the Residential customer class and Small General Service customer class. As can be seen on Exhibit No. 44, Table III, column A, the 2011 average number customers is 397,403 for the Residential customer class and 28,351 for the Small General Service customer class.

With these two principal base level values, the FCC rate can be determined. The annual fixed costs recovered through the energy charges divided by the 2011 average number of customers results in an annual fixed cost recovery per customer, or the FCC rate, shown on Exhibit No. 44, Table III, column K. For the Residential class, the annual fixed cost recovery per customer is $678.96 ($269,822,080 / 397,403). For the Small General Service class, the annual fixed cost recovery per customer is $395.28 ($11,206,634 / 28,351).

Q. How are the class-specific fixed cost amounts established in the initial step used to derive the updated FCE values?

A. The determination of the FCE rate utilizes the Residential and Small General Service weather-normalized energy consumption for the 2011 test year. As can be seen on Exhibit No. 44, Table III, column B, the 2011 weather-normalized annual energy consumption for the Residential customer class is 5,010,676,610 kilowatt-hours ("kWh") and annual energy consumption for the Small General Service class is 148,946,670 kWh.

With these additional principal base level values, the FCE rate can be determined. The annual fixed cost recovered through the energy charges divided by the normalized energy results in an annual fixed cost recovery per kWh, or the FCE rate, shown on Exhibit No. 44, Table III, column L. For the Residential class, the fixed cost recovery per kWh is $0.053849 ($269,822,080 / 5,010,676,610). For the Small General Service class, the annual fixed cost recovery per kWh is $0.075239($11,206,634 / 148,946,670).

Q. Is the methodology used to establish the FCC and FCE rates in this general rate case proceeding the same as that used previously to establish the FCC and FCE rates in Case Nos. IPC-E-07-08 and IPC-E-08-10?

A. Yes it is.

Q. How do the FCC and FCE computed in this filing compare to the FCC and FCE established in the Company's last general rate case, IPC-E-08-10, Case No. 30754.

A. Both the FCC and FCC rates are greater than those currently in effect, which were established using the functionalized classified revenue requirement data in the Company's last filed general rate case, IPC-E-08-10, Case No. 30754. The Company has made significant investments in its infrastructure since that time, and the newly calculated FCC and FCE rates reflect those fixed costs that are being recovered through the Residential and Small General Service energy charges. The magnitude of the amount of fixed costs being recovered through a volumetric rate emphasizes the Company's need to have an FCA true-up mechanism in place. Mr. Larkin describes the determination of the functionalized classified revenue requirement that has been used for the determination of the FCC and FCE.

Q. Are there any other changes being proposed by the Company with regard to the FCA?

A. Yes. The Company is proposing to remove the temporary "pilot" status of Schedule 54 - Fixed Cost Adjustment - and convert it to an ongoing, permanent tariff schedule. The current FCA pilot is set to expire on December 31, 2011. Mr. Cavanagh of the National Resources Defense Council has filed testimony in this case in support of the Company's proposal.

Q. Why is the Company proposing to make Schedule 54 - Fixed Cost Adjustment - an ongoing, permanent tariff schedule?

A. The purpose of the pilot was to test a fixed cost adjustment mechanism designed "to true-up the collection of fixed costs per customer to recover the difference between the fixed costs actually recovered through rates and the fixed costs authorized for recovery in the Company's most recent rate case". Order No. 30267. Results from the first three years of the pilot, and now the last year and a half of the extended pilot, indicate that the true-up mechanism is working as intended and operating to mitigate adverse financial effects for the Company of Demand Side Management ("DSM") by ensuring that the fixed costs authorized for recovery are being trued-up via the FCA mechanism. The mechanism has proven to be fair to both the customer and the Company, providing both a refund and a surcharge throughout the pilot years. The mechanism has also been proven to be reasonable as the individual customer bill impacts, both up and down, have been relatively small.

Q. During the first three years of the pilot, the annual FCA balances for the Residential and Small General Service customer classes were combined to create an equal adjustment for both classes, or spread uniformly to both customer classes on an equal percentage basis. In Staff's comments in IPC-E-11-03, dated March 12, 2011, the Staff's recommendation was to again distribute the surcharge on an equal percentage basis. Is this how the Company originally intended the FCA balances to be distributed under the pilot FCA?

A. No. The annual FCA deferral balance for the residential customer class was originally intended to be an adjustment for the Residential class only. Likewise, and separately, the annual FCA deferral balance for the Small General Service customer class was intended to be an adjustment for the Small General Service class only.

Q. Why were the annual FCA balances for the Residential and Small General Service customer classes combined to create one adjustment for both customer classes?

A. Originally, in the first year of the FCA, the Commission's Staff recommended, and the Commission ultimately approved, a combined adjustment for the Residential and Small General Service customer classes to help offset a FCA rate increase to Small General Service customers. By combining the FCA balances for both customer classes, the Commission was able to balance a rate increase to Small General Service customers with a refund to Residential customers. The result was rate reduction to both customer classes.

During the next three years of the FCA pilot, the FCA balance for both the Residential and Small General Service customer classes were positive amounts. Consistent with the distribution methodology utilized in the first year of the FCA pilot, the Company recommended a combined annual adjustment to help mitigate the individual rate increase to the Small General Service customer class. In turn, the Commission approved a combined rate increase for the Residential and Small General Service customer classes.

Q. How does the Company propose to distribute the annual Residential and Small General Service FCA balances if Schedule 54 is changed to a permanent tariff?

A. For the first four years of the FCA pilot, either the Commission ordered or the Company proposed to recover or refund the FCA deferral balance equally to both classes. Under the proposed permanent tariff, the Company proposes to true-up the Residential and Small General Service FCA by combining the deferral balances of each class and implement rates for each class that represent a uniform percent change. This method of recovery or refund is consistent with the first four years of the FCA Pilot. In addition, by combining the Residential and Small General Service FCA balances and determining the rate adders based on an equal FCA rate adjustment for each class, the overall rate impact to customers in these classes is a more representative total amount of the required fixed cost recovery for each class.

Q. Upon conversion to a permanent FCA, are you proposing any other changes to the pilot FCA provisions set forth in Order No. 30267?

A. Yes. Under the pilot, the Company was required to document each year specific ways it had increased its investment in energy efficiency and DSM as a result of the FCA mechanism. The Company believes that this increased commitment to invest in energy efficiency is now evident and a separate annual reporting requirement is no longer needed with the permanent Tariff Schedule 54. If questions arise as to the Company's commitment toward the acquisition of all cost effective DSM, one can simply review the Company's DSM Annual Report which is filed with the Commission in March of each year. The Company will continue reporting the monthly FCA balance as it now does and will continue to file annual applications seeking approval of the FCA true-up balances. All other provisions will remain the same.

Q. What effective date is the Company proposing for converting Schedule 54 from a pilot schedule to a permanent schedule?

A. The Company is proposing to make Schedule 54 an ongoing, permanent schedule immediately following the completion of the extended pilot which ends December 31, 2011. Therefore, the Company proposes that Schedule 54 become a permanent tariff schedule, effective January 1, 2012.

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

A. Yes, it does.

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BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-11-08

IDAHO POWER COMPANY

YOUNGBLOOD, DI TESTIMONY

EXHIBIT NO. 43

Idaho Power Company
Calculation of Revenue Impact
State of Idaho
2011 General Rate Case Funding
Filed June 1, 2011

Micron
Schedule 26

Line No	Description	(1) Use	(2) Current Base Rate	(3) Current Base Revenue	(4) Proposed Base Rate	(5) Proposed Base Revenue	(6) Revenue Difference	(7) Percent Change
1	Contract kW	720,000.0	$1.49	$1,072,800	$1.71	$1,231,200	$158,400	14.77%
2	Billed kW	673,510.0	$9.75	$6,566,723	$11.20	$7,543,312	$976,589	14.87%
3	Excess Demand kW	0	0.276	$0	0.317	$0	$0	0.00%
4	Billed kWh	464,652,076	0.018394	$8,546,810	0.021124	$9,815,310	$1,268,500	14.84%
5	Total Revenue			$16,186,333		$18,589,822	$2,403,489	14.85%
6	Energy Efficiency Rider		4.75%	$768,851	4.75%	$883,017	$114,166	14.85%
7	FCA Revenue		0.000000	$0	0.000000	$0	$0	0.00%
8	PCA Revenue		(0.000208)	($96,648)	(0.000208)	($96,648)	$0	0.00%
9	Total Billed Revenue			$16,858,536		$19,376,191	$2,517,655	14.93%

Idaho Power Company
Calculation of Revenue Impact
State of Idaho
2011 General Rate Case Funding
Filed June 1, 2011

J R Simplot Company
Schedule 29

Line No	Description	(1) Use	(2) Current Base Rate	(3) Current Base Revenue	(4) Proposed Base Rate	(5) Proposed Base Revenue	(6) Revenue Difference	(7) Percent Change
1	Contract kW	300,000	$2.04	$612,000	$2.34	$702,000	$90,000	14.71%
2	Daily Excess Demand kW	0	0.276	$0	0.320	$0	$0	0.00%
3	Demand (kW)	278,318	6.97	$1,939,876	8.01	$2,229,327	$289,451	14.92%
4	Energy (kWh)	180,758,797	0.018480	$3,340,423	0.021221	$3,835,882	$495,459	14.83%
5	Total Revenue			$5,892,299		$6,767,209	$874,910	14.85%
6	Energy Efficiency Rider		4.75%	$279,884	4.75%	$321,442	$41,558	14.85%
7	FCA Revenue		0.000000	$0	0.000000	$0	$0	0.00%
8	PCA Revenue		(0.000234)	($42,298)	(0.000234)	($42,298)	$0	0.00%
9	Total Billed Revenue			$6,129,885		$7,046,353	$916,468	14.95%

Idaho Power Company
Calculation of Revenue Impact
State of Idaho
2011 General Rate Case Funding
Filed June 1, 2011

Department of Energy
Schedule 30

Line No	Description	(1) Use	(2) Current Base Rate	(3) Current Base Revenue	(4) Proposed Base Rate	(5) Proposed Base Revenue	(6) Revenue Difference	(7) Percent Change
1	Demand	398,604	$7.55	$3,009,460	$8.67	$3,455,897	$446,437	14.83%
2	Total Energy	235,100,000	0.019787	$4,651,924	0.022727	$5,343,118	$691,194	14.86%
3	Total Revenue			$7,661,384		$8,799,015	$1,137,631	14.85%
4	Energy Efficiency Rider		4.75%	$363,916	4.75%	$417,953	$54,037	14.85%
5	FCA Revenue		0.000000	$0	0.000000	$0	$0	0.00%
6	PCA Revenue		(0.000238)	($55,954)	(0.000238)	($55,954)	$0	0.00%
7	Total Billed Revenue			$7,969,346		$9,161,014	$1,191,668	14.95%

Idaho Power Company
Calculation of Revenue Impact
State of Idaho
2011 General Rate Case Funding
Filed June 1, 2011

Hoku
Schedule 32

Line No	Description	(1) Use	(2) Current Base Rate	(3) Current Base Revenue	(4) Proposed Base Rate	(5) Proposed Base Revenue	(6) Revenue Difference	(7) Percent Change
1	First Block Contract Demand	591,387	$2.35	$1,389,760	$2.35	$1,389,760	$0	0.00%
2	First Block Energy	370,006,219	0.061660	$22,814,583	0.061660	$22,814,583	$0	0.00%
3	Second Block Contract Demand	300,000	$4.63	$1,389,000	$5.32	$1,596,000	$207,000	14.90%
4	Second Block Energy	197,100,000	0.028894	$5,695,007	0.033177	$6,539,187	$844,180	14.82%
5	Additional Min. Energy Revenue	0		$0		$0	$0	0.00%
6	Excess Demand Charges							
7	Daily Excess Demand	0	$0.57	$0	$0.65	$0	$0	0.00%
8	Monthly excess Demand	0	$5.71	$0	$6.56	$0	$0	0.00%
9	Excess Energy Charge	0	0.088647	$0	0.101802	$0	$0	0.00%
10	Total Revenue - Block 1			$24,204,343		$24,204,343	$0	0.00%
11	Total Revenue - Block 2			$7,084,007		$8,135,187	$1,051,180	14.84%
12	Total Revenue			$31,288,350		$32,339,530	$1,051,180	3.36%
13	Energy Efficiency Rider - Block 1		4.75%	$1,149,706	4.75%	$1,149,706	$0	0.00%
14	Energy Efficiency Rider - Block 2		4.75%	$336,490	4.75%	$386,421	$49,931	14.84%
15	FCA Revenue		0.000000	$0	0.000000	$0	$0	0.00%
16	PCA Revenue		0.001195	$235,535	0.001195	$235,535	$0	0.00%
17	Total Revenue - Block 1			$25,354,049		$25,354,049	$0	0.00%
18	Total Revenue - Block 2			$7,656,032		$8,757,143	$1,101,111	14.38%
19	Total Billed Revenue			$33,010,081		$34,111,192	$1,101,111	3.34%

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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-11-08

IDAHO POWER COMPANY

YOUNGBLOOD, DI
TESTIMONY

EXHIBIT NO. 44

IDAHO POWER COMPANY
Development of Fixed Cost Adjustment Rate
2011 Test Year
Table I
Class Cost of Service Functionalized Costs

			A	B	C	D	E	F
Line No.	Uniform Tariff Schedules	Rate Schedule No.	COS Revenue Requirement [a]	Generation Fixed Costs [b]	Transmission Fixed Costs [c]	Distribution and Customer Fixed Costs [d]	Total Fixed Costs	Fixed Cost % of Total Cost
							B+C+D	E ÷ A
1	Residential Service	1, 3, 4 & 5	402,235,590	95,105,017	42,427,875	150,523,758	288,056,650	71.6%
2	Small General Service	7	16,196,211	2,222,592	1,050,872	9,478,556	12,752,020	78.7%
3	Large General Service	9	198,565,391	53,272,709	24,106,283	42,451,965	119,830,957	60.3%
4	Dusk/Dawn Lighting	15	523,691	15,780	(83)	401,424	417,121	79.7%
5	Large Power Service	19	92,197,228	25,641,952	12,134,623	9,040,202	46,816,777	50.8%
6	Irrigation Service	24	127,619,827	33,812,776	12,832,792	41,636,060	88,281,628	69.2%
7	Unmetered Service	40	1,141,804	185,494	87,159	506,278	778,931	68.2%
8	Municipal Street Lighting	41	2,107,477	73,243	26,062	1,558,338	1,657,642	78.7%
9	Traffic Control Lighting	42	278,733	46,267	26,509	118,434	191,211	68.6%
10	Special Contracts	26, 29, 30 & 32	76,743,066	17,477,734	9,809,946	2,248,902	29,536,582	38.5%
11	Total Uniform Tariff Schedules		917,609,019				588,319,520	

Notes:
(a) Values for each customer class can be found on Exhibit No. 35 Revenue Requirement Summary, line 45.
(b) Values for each customer class are from Exhibit No. 36, Class Cost of Service Unit Costs, Column D, section "Production - Demand "
(c) Values for each customer class are from Exhibit No. 36, Class Cost of Service Unit Costs, Column D, section "Transmission - Demand "
(d) Values for each customer class are from Exhibit No. 36, Class Cost of Service Unit Costs, Column D, sections "Distribution", "Customer Accounting, "Consumer Information" & "Miscellaneous" (excluding "Energy")

IDAHO POWER COMPANY
Development of Fixed Cost Adjustment Rate
2011 Test Year
Table II
Identification of Interclass Revenue Subsidy

			A	B	C	D	E	F	G
Line No.	Uniform Tariff Schedules	Schedule No.	Proposed Base Rate Revenue (a)	COS Revenue Requirement	Difference	Revenue Short-Fall Identifier	Revenue Short-Fall	Fixed Cost % of Total Cost	Fixed Cost Portion of Rev. Short-Fall
				Table I, Col. A	A - B			Table I, Col. F	E x F
1	Residential Service	1, 3, 4 & 5	412,939,480	402,235,590	10,703,890				
2	Small General Service	7	16,493,381	16,196,211	297,170				
3	Large General Service	9	202,864,074	198,565,391	4,298,683				
4	Dusk/Dawn Lighting	15	1,128,744	523,691	605,053				
5	Large Power Service	19	95,170,387	92,197,228	2,973,159				
6	Irrigation Service	24	118,371,769	127,619,827	(9,248,058)	X	(9,248,058)	69.2%	(6,397,389)
7	Unmetered Service	40	1,174,282	1,141,804	32,478				
8	Municipal Street Lighting	41	2,786,727	2,107,477	679,250				
9	Traffic Control Lighting	42	183,974	278,733	(94,759)	X	(94,759)	68.6%	(65,005)
10	Special Contracts	26, 29, 30 & 32	66,495,576	76,743,066	(10,247,490)	X	(10,247,490)	38.5%	(3,944,015)
11	Total Uniform Tariff Schedules		917,608,394	917,609,019	625		(19,590,307)		(10,406,409)

Weighted Average Fixed Cost % of Short-Fall [b]
53.1%

Notes:
(a) Values for each customer class can be found on Attachment No. 3 to the Application, Summary of Revenue Impact , column "Proposed Base Revenue"
(b) The "Weighted Average Fixed Cost % of Short-Fall" is calculated by dividing the total "Fixed Cost Portion of Rev. Short-Fall" (Col. G) by the total "Revenue Short-Fall" (Col. H)

IDAHO POWER COMPANY
Development of Fixed Cost Adjustment Rate
2011 Test Year
Table III
Derivation of Fixed Cost per Customer and Fixed Cost per Energy Rates

			A	B	C	D	E	F
Line No.	Uniform Tariff Schedules	Schedule No.	2011 Avg. Number of Customers [a]	2011 Sales Normalized (kWh) [a]	COS Fixed Cost	COS Variable Cost	Share of Revenue Short-Fall/Subsidy	Total Base Rate Revenue
					Table I, Col. E	Table I, Col. A - Col. C	Table II, Col. C	C+D+E
1	Residential Service	1, 3, 4 & 5	397,403	5,010,676,610	288,056,650	114,178,940	10,703,890	412,939,480
2	Small General Service	7	28,351	148,946,670	12,752,020	3,444,192	297,170	16,493,381
3	Large General Service	9	30,562	3,492,140,651	119,830,957	78,734,434	4,298,683	202,864,074
4	Large Power Service	19	114	2,040,681,796	46,816,777	45,380,451	2,973,159	95,170,387
5	Irrigation Service	24	16,607	1,679,776,734	88,281,628	39,338,199	(9,248,058)	118,371,769

			G	H	I	J	K	L
Line No.	Uniform Tariff Schedules	Schedule No.	COS Fixed Cost Revenue from Fixed Charges [b]	COS Fixed Cost Revenue from Energy Charges	Fixed Cost Share of Revenue Short-Fall/Subsidy	Total Fixed Cost Revenue from Energy Charges	Calculation of FCC ($/Cust./Yr.)	Calculation of FCE ($/kWh)
				C-G	E x 53.1	H + I	J ÷ A	J ÷ B
1 (Cont.)	Residential Service	1, 3, 4 & 5	23,920,497	264,136,153	5,685,927	269,822,080	**$ 678.96**	**$ 0.053849**
2 (Cont.)	Small General Service	7	1,703,243	11,048,777	157,857	11,206,634	**$ 395.28**	**$ 0.075239**
3 (Cont.)	Large General Service	9	45,839,941	73,991,016	2,283,469	76,274,485	$ 2,495.73	$ 0.021842
4 (Cont.)	Large Power Service	19	28,690,045	18,126,732	1,579,348	19,706,079	$ 172,860.35	$ 0.009657
5 (Cont.)	Irrigation Service	24	28,669,344	59,612,284	(4,912,586)	54,699,698	$ 3,293.77	$ 0.032564

Notes: