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IDAHO PUBLIC UTILITIES COMMISSION

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 IN IDAHO.	)	**CASE NO. IPC-E-11-08**

DIRECT TESTIMONY OF RANDY LOBB IN SUPPORT OF THE STIPULATION AND SETTLEMENT

IDAHO PUBLIC UTILITIES COMMISSION

OCTOBER 7, 2011

Q. Please state your name and business address for the record.

A. My name is Randy Lobb and my business address is 472 West Washington Street, Boise, Idaho.

Q. By whom are you employed?

A. I am employed by the Idaho Public Utilities Commission as Utilities Division Administrator.

Q. What is your educational and professional background?

A. I received a Bachelor of Science Degree in Agricultural Engineering from the University of Idaho in 1980. I then worked for the Idaho Department of Water Resources from June of 1980 to November of 1987. I received my Idaho license as a registered professional Civil Engineer in 1985 and began work at the Idaho Public Utilities Commission in December of 1987. My duties at the Commission currently include case management and oversight of all technical Staff assigned to Commission filings. I have conducted analysis of utility rate applications, rate design, proposed tariffs and customer petitions. I have testified in numerous proceedings before the Commission including cases dealing with rate structure, Cost of Service, power supply, line extensions, regulatory policy and facility acquisitions.

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

A. The purpose of my testimony is to describe the Stipulation (the Proposed Partial Settlement) filed in this case and to explain the rationale for Staff's support. I will also present Staff's proposed reduction in the Energy Efficiency Tariff Rider.

Q. Please summarize your testimony.

A. The Stipulation resolves most of the issues in the general rate case and is agreed to by all parties but one. Based on Staff's audit of Idaho Power Company's results of operations, evaluation of proposed proforma adjustments and consideration of all issues associated with Cost of Service, rate design and customer impact, Staff supports the Proposed Partial Settlement resulting in an increase in base rates of 4.19%. Staff further proposes reducing the Energy Efficiency Tariff Rider (Schedule 91) by 0.75%, thereby reducing the overall net increase to 3.44%. Finally, based on its review of the Company's filing and in consideration of issues and concerns expressed by other parties to the case in settlement negotiations, Staff believes the broad Proposed Partial Settlement is in the public interest, is just and reasonable and should be approved by the Commission.

Q. How is your testimony organized?

A. My testimony is subdivided under the following headings:

Stipulation Overview

Q. Please provide an overview of the Stipulation and Proposed Partial Settlement.

A. The Stipulation provides for an annual overall increase in electric base revenue of $34 million or 4.07%. The increase, spread uniformly to all customer classes, is actually 4.19% because the overall increase does not apply to Hoku Material's first block energy. The Stipulation encourages the Commission to make the new rates effective on January 1, 2012.

The Stipulation specifies annual power supply cost levels for the Power Cost Adjustment (PCA) mechanism, the amortization schedule for Bennett Mountain combustor inspection costs, and the amortization schedule for the Light Detection and Radar Survey (LIDAR) costs. It also specifies a 7.86% overall rate of return (ROR) without specifying a new authorized Return on Equity (ROE).

Although the Stipulation comprehensively settles all revenue requirement issues in the case, it does not specify revenue adjustments to the Company's case or an authorized ROE. While the Stipulation uses the Company's Class Cost of Service Study (COS): 1) to establish fixed costs for the Fixed Cost Adjustment mechanism (FCA); 2)to reset the Load Change Adjustment Rate (LCAR) for the PCA; and 3)to modify rate components within individual customer classes, the COS has not been used to spread the revenue increase among customer classes. Rather, the Stipulation uniformly spreads revenue among the classes. The Stipulation is attached as Staff Exhibit No. 101.

Q. Does the Stipulation resolve all issues presented by the Company in its original filing?

A. No. Several issues remain. Two issues will be addressed in separate dockets: 1) Whether the FCA pilot should be made permanent; and 2) Overhead amounts associated with line extensions under Rule H. Three other issues are not resolved and will be addressed at hearing. These three unresolved issues are: 1) the level of funding for Low Income Weatherization Assistance; 2) the calculation of facility charges associated with industrial Schedules 9 and 19 customers; and 3) the appropriate level of the Energy Efficiency Rider.

Q. How does the annual base revenue requirement increase proposed in the Stipulation compare to the increase originally proposed by Idaho Power?

A. The Company originally proposed increasing annual base electric revenue by $83 million or 9.9%. The Stipulation would increase annual base electric revenue by $34 million or approximately 41% of the original request.

The Settlement Process

Q. Would you please describe the process leading to the Stipulation?

A. Yes. The Company filed its rate application with the Commission on June 1, 2011 and Staff immediately began its review. The Commission set a July 1, 2011 intervention deadline. Parties ultimately approved for intervention included: The Community Action Partnership Association of Idaho (CAPAI), the U.S. Department of Energy (DOE), the Industrial Customers of Idaho Power (ICIP), the Idaho Irrigation Pumpers Association (IIPA), Kroger Company, Micron, the Northwest Energy Coalition (NWEC), the Idaho Conservation League (ICL), the Snake River Alliance (SRA) and Hoku Materials.

Once parties to the case were determined, they met to establish a procedural schedule that included production request deadlines, direct and rebuttal testimony prefile dates, hearing dates and two dates for settlement negotiations. The settlement conferences were held on August 31 and September 8, 2011 in the Commission hearing room. All parties participated in both conferences.

Settlement discussions focused primarily on revenue requirement with specific discussion regarding ROE, Company salaries, Power Supply Costs and amortization of a variety of test year expenses. Other topics discussed included the FCA pilot program, Cost of Service, low income weatherization, facilities charges, line extension overheads, rate design and the appropriate level of the Energy Efficiency Rider.

The parties stated their positions on the various revenue requirement issues and presented proposals on all of the other topics. There was frank and thorough discussion of all issues. Tentative agreement was reached by the end of the conference on the 8th by all parties except CAPAI.

Q. Were there further efforts and discussions about issues after September 8th?

A. Yes, the Energy Efficiency Rider level issue was still in dispute after the September 8th conference. After further discussions, the parties agreed to designate the DSM Rider issue as unresolved and address it at the December technical hearing. After several rounds of review, all parties except CAPAI signed the Stipulation and it was submitted to the Commission for approval on September 23, 2011.

Q. How did Commission Staff evaluate the Proposed

Partial Settlement to determine that it was reasonable?

A. As in prior cases, Staff evaluated whether a settlement would result in a better outcome for customers than could reasonably be anticipated through litigation. In this case, Cost of Service and revenue spread to the various customer classes, in addition to the overall revenue requirement increase, were of primary concern. Staff evaluated the Stipulation's merits by comparing it to what might be expected if all of the parties filed testimony and the case proceeded to hearing. Staff believes the Stipulation, arrived at through give and take of all the parties, results in both a reasonable overall base rate increase and equitable treatment of all customer classes.

Q. Doesn't the Commission decide what the revenue requirement increase should be and how the increase should be allocated to each customer class?

A. Yes. The Commission makes the final decision but its decision must be based on the record presented through testimony and other evidence. The parties to the case make revenue requirement adjustment recommendations on the record for the Commission to consider. The parties also make recommendations regarding Cost of Service and how the increase should be allocated to the various customer classes. The potential outcome at hearing must therefore be evaluated based on both the expected quality and quantity of party recommendations presented and on what recommendations the Commission might ultimately accept.

Revenue Adjustments

Q. What type of adjustments to the Company's proposed revenue requirement had Staff identified and what was the dollar value of those adjustments?

A. Staff aggressively evaluated the Company's proposed revenue requirement increase and proposed a variety of adjustments at the settlement conferences. Two of the largest adjustments identified by Staff were ROE and salaries. Staff maintained that the Company's proposed ROE of 10.5% was excessive and unjustified under current economic conditions. Similarly, Staff maintained that salary increases awarded to employees in 2011 and 2012 were excessive and should not be allowed for cost recovery. The Staff positions of lowering the ROE to a more reasonable level in combination with lower employee salaries would, in our judgment, reduce the Company's revenue requirement request by more than $16 million.

Staff also proposed various other adjustments including amortization of test year expenses incurred for the Bennett Mountain combustor inspection and the LIDAR Survey costs; removal of Fish and Game and civic organization expenses; adjustments for FERC allocated costs, smart grid investments, board of directors' compensation, P-Card expenses and revenue normalization. The combined effect of other Staff-proposed adjustments may have reduced revenue requirement by an additional $7.8 million.

Q. Did Staff take a position on any other revenue requirement issues?

A. Yes. The single largest adjustment proposed by Staff was removing $23.9 million in Cogeneration and Small Power Production (CSPP) costs from base rate recovery. The identified CSPP costs were associated with contracted wind projects anticipated to come on line in 2011 or 2012.

The Company had included this level of CSPP costs to offset $23.9 million in first block revenue currently generated from the Hoku service contract. Both revenue from the contract and the CSPP costs are captured in the PCA as power supply costs if not captured in base rates. Staff agreed that Hoku revenues should be included in base rates because they were actually being generated. The Company's intent was to hold net power supply costs in base rates at levels previously approved by the Commission. However, Staff did not believe it was necessary or appropriate to include CSPP cost in base rates because they were projected based on anticipated project online dates and were not actually being incurred. If the projects do come on line and costs are incurred, they will flow through the PCA at 100% if they are not included in base rates. Removing the

CSPP cost offset to the Hoku revenue significantly decreases the required base rate increase and moves recovery of the CSPP costs to the PCA if and when they are actually incurred.

Q. How confident was Staff that its adjustments could be justified on the record and accepted by the Commission upon hearing?

A. Staff was reasonably confident that at least some of the proposed adjustments would be accepted by the Commission at hearing. Similar ROE and employee salary adjustments were favorably addressed by the Commission in the recent Pacificorp general rate case (PAC-E-10-7). Staff also believed that the Commission would accept the proposed treatment of future CSPP costs through the PCA. However, other proposed adjustments have not been addressed at hearing and were less certain to be accepted by the Commission. Staff was not as confident that it could successfully defend the other adjustments on the record in the face of rebuttal testimony provided by the Company.

Q. Did any of the other parties propose adjustments to the Company's requested revenue requirement?

A. Yes. Other parties suggested adjusting ROE, limiting test year proforma adjustments, modifying revenue normalization and adjusting non-labor O&M. However, most of these suggestions were already incorporated in Staff adjustments, previously decided by the Commission, or in Staff's view, were without sufficient support. Consequently, Staff evaluated the revenue requirement settlement primarily based on Staff adjustments alone.

Q. Why doesn't the Stipulation specify a new ROE and the other revenue requirement adjustments?

A. Rather than identifying a specific ROE, the Stipulation specifies an overall ROR of 7.86% which combines ROE, capital structure and cost of debt. Specifying a ROR establishes a range of possible input parameters and represents a compromise to facilitate agreement on the overall revenue requirement.

Although the Stipulation is silent on the value of many adjustments considered in arriving at the specified revenue requirement increase, it does specify a few. For example, the Stipulation incorporates Staff's proposed amortization of Bennett Mountain Combustor Inspection costs over a four-year period and a ten-year amortization of LIDAR survey cost. The Stipulation also specifies the base level of Net Power Supply Expenses (NPSE) for use in the PCA that includes Hoku sales revenue but excludes offsetting CSPP costs.

Cost of Service

Q. Please describe the Stipulation as to customer class Cost of Service and revenue spread among the classes.

A. The Stipulation does not accept any specific class Cost of Service methodology in spreading the revenue increase to the customer classes. The parties agree that the Company's class Cost of Service can be used in this case for the limited purpose of establishing fixed costs for the FCA mechanism, establishing an LCAR for use in the PCA and for setting various rate components within individual customer classes. Fixed costs in the FCA and the LCAR for the PCA must be updated periodically, as are base rate power supply costs, for the mechanisms to function properly. The Company's proposed class Cost of Service provides a reasonable basis for establishing these components.

Q. Why was the Company's proposed Cost of Service not used to spread the revenue increase among the customer classes?

A. Class Cost of Service has always been one of the most contentious issues addressed in general rate cases. Appropriate Cost of Service methodology and equitable revenue spread to customer classes was also an important issue in this case. Acceptance of the Company's proposed class Cost of Service would have resulted in increases significantly above the overall average for irrigators and high load factor industrial customers while residential customers would see increases below the average. The proposed uniform increase for all customer classes represents a compromise that allowed the parties to achieve a comprehensive revenue requirement settlement.

Q. Why did Staff agree to a uniform spread given the results of the Company's COS?

A. Staff believes that some move toward Cost of Service should be made based on the Company proposed Cost of Service study. Therefore, in order to reach compromise on rate spread, Staff evaluated the effects of moving $23.9 million in CSPP costs from base rate recovery to PCA recovery. Staff determined that if CSPP costs are incurred in 2011/2012 as anticipated by the Company, high energy users such as irrigators and large industrial customers will pay a larger, disproportionate share of the costs through the PCA. In fact, Staff analysis showed that the spread of potential CSPP cost combined with the uniform base rate increase results in an overall revenue spread that generally reflects the Company's proposed class Cost of Service. Consequently, Staff supports the uniform base revenue spread in this case.

Q. Is it reasonable to further delay consideration of class Cost of Service methodology until the next general rate case?

A. Yes. If reasonable allocation can occur with the base rate settlement and subsequent treatment of future CSPP cost through the PCA, then class Cost of Service litigation can wait until the next general rate case.

The reality of class Cost of Service is that it is a moving target that is never fully resolved or fully implemented. Nevertheless, the longer the Commission goes without significant rate movement based on Cost of Service the more difficult it will be to implement in the future.

Rate Design

Q. How are individual rate components proposed to be changed under the Stipulation?

A. The Parties agreed to accept, for the purposes of this case, the Company proposal to adjust rate components within each class based, in part, on the Company's proposed Cost of Service results. Specifically, the Stipulation states that: "the signing parties agree that the existing tariff rate components for all schedules should be increased in a manner that is consistent with the rate design originally filed by the Company in this case…" For many rate components within each customer class, the Company's originally-filed rate design incorporates a 5% move toward Cost of Service as identified in the Company's Cost of Service study.

Q. How does the proposed rate design impact the various customer classes?

A. For Residential Schedule 1 customers, the customer charge will increase from $4 to $5 per month. The increase in the energy rate components will depend on the season of the year. Summer energy rates for each block will increase by approximately 4.1%. The first and second-tier energy rates in the non-summer period will increase by approximately 3.1%, while the third-tier energy rate will remain unchanged.

For Residential Schedules 3, 4 and 5, the Stipulation applies the Company-proposed change in the customer charge from $4 to $5 per month. The energy rate for Schedule 3, Master Metered Mobile Home Parks, increases by 4.13%. With respect to The Energy Watch Program (Schedule 4) and the Time-Of-Day (TOD) Program (Schedule 5), the Stipulation accepts the Company's proposed modification from three daily TOD and tiered block rates to seasonal peak and off-peak rates.

Rate Components for Small General Service (Schedule 7), Large General Service (Schedule 9), Large Power Service (Schedule 19) and Agricultural Irrigation Service (Schedule 24), have all been modified based in part on the Cost of Service study to achieve the revenue requirement allocated to each class. The individual rate components proposed for each class are shown in Exhibit No. 3 to the Stipulation.

Q. Please explain Staff's support for rate component modification based on the Company's COS.

A. Staff has generally supported the Company's COS with respect to class revenue requirement. Staff has not necessarily supported Cost of Service to adjust rate components. However, in the spirit of compromise and because Cost of Service can provide insight into the size and relationship of the rate components within each customer class, Staff agreed to the Company's rate design proposal in this case. Staff additionally notes that the Company's proposed Cost of Service adjustment was relatively modest and was made smaller by the reduced revenue requirement increase.

Q. Why does Staff support the increase in the residential customer charge?

A. Staff supports the customer charge increase as part of the negotiated Settlement and to recognize the Company's increased investment to install sophisticated automated meters and the customer information system infrastructure needed for operation. The $5 customer charge is also consistent with Avista's monthly charge of $5.25 and Rocky Mountain Power's monthly customer charge of $5.

Q. Could you please explain Staff's support for the proposed changes in the residential non-summer energy rates?

A. Yes. Staff agrees that energy production costs in the non-summer period are lower than the summer period and should therefore be reflected in the relative energy rates paid by customers. Staff also recognizes that customers with all electric homes are most severely impacted by the third block energy rates in the non-summer period. Staff believes that maintaining the third block non-summer energy rate at its current level will moderate the impact on this group of customers while continuing to provide a reasonable price signal. Staff further believes that rural Idaho Power customers with all electric homes have few options to control winter electric consumption when natural gas is not available. The proposed rate design helps reduce the cost burden on those customers with non-discretionary winter heating load.

Q. What is the impact of the stipulated changes on residential and small commercial customer bills?

A. A residential customer using 1000 kWh per month will see an average monthly bill increase of 4.54% from $73.33 to $76.66. A residential customer using 4000 kWh per month will see a bill increase of 2.44% from $329.09 to $337.13 per month. A small commercial customer using 1000 kWh per month will see an average monthly increase of 3.01% per month from $92.33 to $95.11. Staff Exhibit No. 102 shows how residential and small commercial monthly bills will change for different usage levels.

Q. Could you please describe Staff's support for the modification and expansion of the Company's Energy Watch and

Time-Of-Day Programs?

A. Yes. Staff fully supports expanding these voluntary programs to allow customers to choose a rate plan that best fits their needs. Expanding these programs also better meets the Company's needs in terms of reducing load on peak hours and during critical peak periods. Staff fully supports the rate design that provides two, time-of-use rate periods throughout the year. The rate design is easier for customers to understand and better reflects the existing peak, off peak, wholesale energy markets. Finally, expanding the program makes better use of the Company's recently installed automated meter technology. These meters were designed to provide just the type of hourly data that allows these pricing programs to be implemented.

Separate Dockets

Q. The Stipulation removes two issues from consideration in this case: 1) a permanent FCA mechanism, and 2) changes to Rule H line extension tariff. Why were separate dockets established to consider these issues?

A. The FCA mechanism was set up on a pilot basis after more than two years of workshops and considerable review by multiple parties. The pilot itself has been in place for approximately 5 years. In 2010, the Commission denied the Company's request to make the FCA permanent citing issues and concerns raised by various parties.

Consequently, Staff believes it is inappropriate to consider whether the FCA should be made permanent as part of this general rate case. Staff maintains that all of the issues associated with the FCA should be heard in a separate docket with appropriate parties focused on the merits of a permanent FCA.

Likewise, Staff maintains that modifying the Rule H line extension tariff should be considered outside a general rate case. The proposed increase of overhead charges is a non-recurring charge and may be properly reviewed in a separate proceeding.

The Energy Efficiency Rider

Q. What is Staff's proposal with respect to the Energy Efficiency Tariff Rider?

A. Staff proposes that the Energy Efficiency Tariff Rider be reduced from the current 4.75% of billed revenues to 4.0% of billed revenues for applicable schedules. This reduction helps to mitigate the increase in base rates and recognizes that approximately $16.5 million in annual DSM expenditures have been removed from tariff rider recovery and included in base rates.

Q. Will the Company be required to reduce its expenditures for DSM programs as a result of the tariff rider reduction?

A. No, the revenue provided to support DSM programs through a combination of base rates and the tariff rider will be significantly greater than needed to support existing Company DSM programs. In his testimony, Staff witness English describes and breaks down the Company's annual DSM expenditures, the annual revenue needed from the tariff rider and the annual revenue generated from the tariff rider at 4.0% of billed revenues.

Q. Overall, how does the stipulated base rate increase and the Energy Efficiency Tariff Rider reduction impact customers?

A. The Stipulation specifies an overall base rate increase of 4.19% and, when coupled with the 0.75% reduction in the Energy Efficiency Rider, results in a net rate increase of 3.44%.

Q. Does the Staff's proposal to reduce the Energy Efficiency Tariff Rider in any way represent a reduced commitment to DSM and energy efficiency?

A. No, not at all. Staff sees the partial shift in DSM cost recovery as an opportunity to increase funding for DSM programs while simultaneously mitigating the impact of the proposed base rate increase. This proposal results in enhanced ability to provide DSM programs and a more limited overall rate increase in a difficult economy.

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

A. Yes, it does.

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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 IN IDAHO.	)	CASE NO. IPC-E-11-08 STIPULATION

This stipulation ("Stipulation") is entered into by and among Idaho Power Company ("Idaho Power" or "Company"), the Staff of the Idaho Public Utilities Commission ("Staff"), and other parties to the above referenced case as indicated by their signatures to this settlement Stipulation. The Company, Staff, and other signing parties are referred to individually as a "Signing Party" or collectively referred to as the "Signing Parties."[1]

I. INTRODUCTION

1. The terms and conditions of this Stipulation are set forth herein. The Signing Parties agree that this Stipulation represents a fair, just, and reasonable compromise of the

[1] Although all parties to this case (including the Staff, the Company, and all intervenors identified in paragraph II.3) participated in settlement discussions, CAPAI is not a Signing Party.

issues in this proceeding and that this Stipulation is in the public interest. The Signing Parties maintain that the Stipulation and its acceptance by the Idaho Public Utilities Commission ("IPUC" or "Commission") represent a reasonable resolution of most issues identified in this matter. The issues that remain unresolved, as specified below, will be addressed either in this rate case proceeding or in separate proceedings, but will not disturb the agreements reached in this Stipulation. Therefore, the Signing Parties recommend that the Commission, in accordance with RP 274, approve the Stipulation and all of its terms and conditions without material change or condition.

II. <u>BACKGROUND</u>

2. On June 1, 2011, Idaho Power filed an Application in this case seeking authority to increase the Company's base rates an average of 9.9 percent. If approved, the Company's revenues would have increased approximately $83 million annually. Idaho Power proposed that the rate increase be spread in varying degrees among all major customer classes and special contract customers. The Company requested that new rates become effective July 1, 2011, with the expectation that the Commission would suspend implementation of the Company's proposed rates for the statutory period set forth in Idaho Code § 61-622. The Commission suspended the effective date of the proposed rates for thirty (30) days plus five (5) months from July 1, 2011, in Order No. 32272, which also aligned with the terms of the stipulation approved in Case No. IPC-E-09-30 requiring that any changes to the Company's base rates would not become effective until 2012.

3. Petitions to intervene in this proceeding were filed by the Community Action Partnership Association of Idaho ("CAPAI"), Idaho Irrigation Pumpers Association, Inc. ("IIPA"), the Industrial Customers of Idaho Power ("ICIP"), Micron Technology, Inc.

("Micron"), the United States Department of Energy ("DOE"), The Kroger Co. ("Kroger"), the Idaho Conservation League, Snake River Alliance, the NW Energy Coalition, and Hoku Materials, Inc. ("Hoku"). By various orders, the Commission granted these interventions. IPUC Order Nos. 32266, 32267, 32282, 32285, 32288, 32289, 32316, and 32349.

4. On July 20, 2011, an informal scheduling conference was convened by Staff for the purpose of developing a schedule for holding hearings and completing discovery. All parties attended the settlement conferences on August 31, 2011, and September 8, 2011.

5. Based upon these settlement discussions, as a compromise of the positions in this case, and for other consideration as set forth below, the Signing Parties agree to the following terms:

III. TERMS OF THE STIPULATION

6. Revenue Requirement. The Signing Parties agree that Idaho Power shall be allowed to implement revised tariff schedules designed to recover $34 million in additional annual revenue from Idaho jurisdictional base rates, which is a 4.07 percent overall increase in the Company's annual Idaho jurisdictional base rate revenues. The Signing Parties further agree that the $34 million increase represents a compromise of the revenue requirement positions in the case for the purpose of settlement and that the agreed upon amount should be approved by the Commission in its entirety without further adjustment for any factors other than those described in Section 11 of this Stipulation. In determining the $34 million additional revenue requirement, the Signing Parties agree on certain revenue requirement inputs to be explicitly identified in this Stipulation. These are as follows:

(a) Net Power Supply Expense ("NPSE"). For purposes of calculating the Power Cost Adjustment ("PCA") mechanism, the system net power supply cost used to determine the $34 million of additional revenue requirement increase is $208,100,936. This base level of NPSE includes $11,252,265 of base level demand response incentive payments that the Signing Parties agree should be tracked as part of the PCA as proposed by the Company in its original Application and includes $23,921,466 of retail sales revenue associated with Hoku's First Block energy sales that is created as an offset to power supply expenses in the PCA. Exhibit No. 1 attached hereto details the individual PCA component amounts by Federal Energy Regulatory Commission account that have been agreed upon by the Signing Parties.

(b) Amortizations. The Signing Parties agree to a deferral of certain 2011 expenses with multi-year amortizations of those deferred amounts. The Signing Parties agree to a deferral of $299,546 in expenses associated with the Bennett Mountain combustor inspection with a four-year amortization period beginning on the date that the Company's new base rates become effective. Further, the Signing Parties agree to a deferral of $436,047 in expenses associated with the Light Detection and Ranging ("LiDAR") survey with a ten-year amortization period beginning on the date that the Company's new base rates become effective.

(c) Rate of Return. The Signing Parties agree that it would be just and reasonable for the Commission to allow the Company to earn a 7.86 percent rate of return on an authorized Idaho jurisdictional rate base of $2,355,906,412. In addition, the Signing Parties agree that it would be just and reasonable for the Commission to allow the Company to earn an authorized rate of return of 7.86 percent in any Idaho Power regulatory matter to be determined by the Commission until it is subsequently changed by Commission order.

7. Rate Spread. The Signing Parties agree that the above-described $34 million revenue requirement increase should be recovered by implementing tariffs in conformance with the attached Exhibit No. 2, which increase the rates for each customer class and special contracts customers by a uniform percentage amount of approximately 4.19 percent.[2] The Signing Parties further agree that the Company's proposed cost-of-service study will be used to determine fixed costs for purposes of the Fixed Cost Adjustment ("FCA") mechanism until the Commission approves a different cost-of-service study. The Signing Parties agree that the acceptance of the use of the Company's cost-of-service study in the context of the FCA for the purposes of settlement is not acceptance of any methodology underlying the Company's cost-of-service study results, is not binding on the Signing Parties in future general rate case proceedings, and does not imply agreement on the merits of the methodology.

8. Rate Design. In determining the individual rates for each tariff schedule, the Signing Parties agree to use the 2011 Test Year customer billing determinants as proposed by the Company in this case with the exception of agreed upon adjustment in Schedule 1 residential energy components. The Signing Parties agree that the existing tariff rate components for all schedules should be increased in a manner that is consistent with the rate design originally filed by the Company in this case, including increasing the

[2] The resulting uniform percentage increase amount of approximately 4.19 percent is greater than the overall increase of 4.07 percent because the overall increase does not apply to First Block rates for special contract customer Hoku Materials, Inc.

monthly Service Charge for residential Schedules 1, 4, and 5 from $4.00 to $5.00. The attached Exhibit No. 3 details the specific rates for each schedule.

9. Load Change Adjustment Rate. In determining the agreed-upon Load Change Adjustment Rate ("LCAR") to be applied in the Company's PCA, the Signing Parties agree to use Idaho Power's filed class cost-of-service methodology to determine the generation-related Idaho jurisdictional revenue requirement that has been classified as energy-related. The resulting LCAR of $18.16 per megawatt-hour was developed using 2011 normalized system-wide firm loads in the amount of 14,822,063 megawatt-hours as proposed by the Company in this case. Exhibit No. 4 to the Stipulation details the derivation of the agreed upon LCAR that is to become effective on the date that the Company's new base rates become effective.

10. Separate Proceedings. To facilitate further investigation and participation, the Signing Parties agree that Idaho Power will initiate separate, subsequent proceedings related to:

(a) Increasing overhead amounts paid by persons or entities requesting services under the Company's Rule H line extension tariff; and

(b) Whether the FCA pilot program should be made permanent. The Signing Parties agree, however, that the FCA case should be processed to allow a final Order to be issued no later than March 30, 2012. To allow for the timely processing of the FCA case, the Signing Parties request that the Commission decide at its earliest convenience (after a 14-day response period per RP 256) whether to process the FCA case as a separate docket. The Signing Parties further agree that if the Commission approves or extends the FCA program beyond 2011, no Signing Party will object to retroactively applying the subsequently determined fixed costs per customer ("FCC") and fixed costs per energy ("FCE") inputs to January 1, 2012.

11. Unresolved Issues. The Signing Parties were not able to reach consensus on the following issues, which will proceed to hearing under the schedule established in Order No. 32316:

(a) The level of the Energy Efficiency Rider;

(b) Low-income Weatherization Assistance for Qualified Customer program funding; and

(c) The facility charge rate determination methodology used to develop facilities charges assessed to Schedule 19 customers and issues relating to the ownership of facilities subject to facilities charges. However, the Signing Parties agree that any revenue requirement impacts resulting from changes to the facility charge methodology or changes in property ownership shall be directly assigned to Schedule 19 customers in the form of a base rate increase or reduction so that no other customer classes shall be impacted by any resulting change.

12. Rate Effective Date. The Signing Parties encourage the Commission to issue its Order approving the agreed-upon rates contained in this Stipulation to become effective on January 1, 2012.

13. The Signing Parties agree that this Stipulation represents a compromise of the positions of the Signing Parties in this case. As provided in RP 272, other than any testimony filed in support of the approval of this Stipulation, and except to the extent necessary for a Signing Party to explain before the Commission its own statements and positions with respect to the Stipulation, all statements made and positions taken in

negotiations relating to this Stipulation shall be confidential and will not be admissible in evidence in this or any other proceeding.

14. The Signing Parties submit this Stipulation to the Commission and recommend approval in its entirety pursuant to RP 274. The Signing Parties shall support this Stipulation before the Commission, and shall not appeal a Commission Order approving the Stipulation or an issue resolved by the Stipulation. If this Stipulation is challenged by anyone who is not a Signing Party, the Signing Parties reserve the right to file testimony, cross-examine witnesses, and put on such case as they deem appropriate to respond fully to the issues presented, including the right to raise issues that are incorporated in the settlements embodied in this Stipulation. Notwithstanding this reservation of rights, the Signing Parties agree that they will continue to support the Commission's adoption of the terms of this Stipulation.

15. If the Commission rejects any part or all of this Stipulation, or imposes any additional material conditions on approval of this Stipulation, each Signing Party reserves the right, upon written notice to the Commission and the other Signing Parties to this proceeding, within fourteen (14) days of the date of such action by the Commission, to withdraw from this Stipulation. In such case, no Signing Party shall be bound or prejudiced by the terms of this Stipulation, and each Signing Party shall be entitled to seek reconsideration of the Commission's Order, file testimony as it chooses, cross-examine witnesses, and do all other things necessary to put on such case as it deems appropriate. In such case, the Signing Parties immediately will request the prompt reconvening of a prehearing conference for purposes of establishing a procedural schedule for the completion of the case. The Signing Parties agree to cooperate in development of a

schedule that concludes the proceeding on the earliest possible date, taking into account the needs of the Signing Parties in participating in hearings and preparing briefs.

16. The Signing Parties agree that this Stipulation is in the public interest and that all of its terms and conditions are fair, just, and reasonable.

17. No Signing Party shall be bound, benefited, or prejudiced by any position asserted in the negotiation of this Stipulation, except to the extent expressly stated herein, nor shall this Stipulation be construed as a waiver of rights unless such rights are expressly waived herein. Except as otherwise expressly provided for herein, execution of this Stipulation shall not be deemed to constitute an acknowledgment by any Signing Party of the validity or invalidity of any particular method, theory, or principle of regulation or cost recovery. No Signing Party shall be deemed to have agreed that any method, theory, or principle of regulation or cost recovery employed in arriving at this Stipulation is appropriate for resolving any issues in any other proceeding in the future. No findings of fact or conclusions of law other than those stated herein shall be deemed to be implicit in this Stipulation.

18. The obligations of the Signing Parties are subject to the Commission's approval of this Stipulation in accordance with its terms and conditions and upon such approval being upheld on appeal, if any, by a court of competent jurisdiction.

19. This Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

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DATED this 30th day of September 2011.

Idaho Power Company

By Lisa D. Nordstrom
Lisa D. Nordstrom
Attorney for Idaho Power Company

Idaho Public Utilities Commission Staff

By__________
Donald H. Howell, II
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Idaho Irrigation Pumpers Association, Inc.

By__________
Eric L. Olsen
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Industrial Customers of Idaho Power

By__________
Peter J. Richardson
Attorney for Industrial Customers of Idaho Power

Micron Technology, Inc.

By__________
Thorvald Nelson
Attorney for Micron Technology, Inc.

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By__________
Arthur Perry Bruder
Attorney for U.S. Department of Energy

The Kroger Co.

By__________
Kurt J. Boehm
Attorney for The Kroger Co.

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Hoku Materials, Inc.

By__________
Dean J. Miller
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NW Energy Coalition

By__________
Nancy Hirsh
Policy Director for NW Energy Coalition

Snake River Alliance

By__________
Ken Miller
Clean Energy Program Director for Snake River Alliance

DATED this _____ day of September 2011.

Idaho Power Company

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Ken Miller
Clean Energy Program Director for Snake River Alliance

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DATED this 21st day of September 2011.

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Nancy Hirsh
Policy Director for NW Energy Coalition

Snake River Alliance

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Ken Miller
Clean Energy Program Director for Snake River Alliance

DATED this 30th day of September 2011.

Idaho Power Company

By Lisa D. Nordstrom
Lisa D. Nordstrom
Attorney for Idaho Power Company

Idaho Irrigation Pumpers Association, Inc.

By____________________
Eric L. Olsen
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By Fred Schmidt
~~Thorvald Nelson~~ Fred Schmidt
Attorney for Micron Technology, Inc.

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Nancy Hirsh
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DATED this 30th day of September 2011.

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Lisa D. Nordstrom
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By Ken Miller
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DATED this 22 day of September 2011.

Idaho Power Company

By________________________
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Clean Energy Program Director for Snake River Alliance

DATED this 30th day of September 2011.

Idaho Power Company

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Attorney for Idaho Power Company

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Ken Miller
Clean Energy Program Director for Snake River Alliance

DATED this 30th day of September 2011.

Idaho Power Company

By Lisa D. Nordstrom
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NW Energy Coalition

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Nancy Hirsh
Policy Director for NW Energy Coalition

Snake River Alliance

By Ken Miller
Ken Miller
Clean Energy Program Director for Snake River Alliance

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-11-08

IDAHO POWER COMPANY

EXHIBIT NO. 1

Power Cost Adjustment Components using JSS Allocation Factors

		Total System	Allocation		Idaho Jurisdiction
account 501, coal	$	167,718,084	95.00%	$	159,327,268
account 536, water for power	$	1,828,640	95.22%	$	1,741,299
account 547, gas	$	6,062,472	95.00%	$	5,759,183
account 555, non PURPA	$	66,689,601	95.00%	$	63,353,192
account 565, transmission	$	8,262,000	95.00%	$	7,848,661
account 447, surplus sales	$	92,642,114	95.00%	$	88,007,308
account 442, Hoku First Block Revenues	$	23,921,466	95.37%	$	22,814,583
Net of 95% accounts	$	133,997,217		$	127,207,712
account 555, PURPA	$	62,851,454	95.00%	$	59,707,063
Net of 100% Accounts	$	62,851,454		$	59,707,063
account 555, Demand Response Incentives	$	11,252,265	100.00%	$	11,252,265.00
Total NPSE	$	208,100,936		$	198,167,040

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-11-08

IDAHO POWER COMPANY

EXHIBIT NO. 2

Idaho Power Company
Calculation of Revenue Impact
State of Idaho
2011 GRC Stipulation Funding
Effective January 1, 2012

Summary of Revenue Impact

Line No	Tariff Description	Rate Sch. No.	Average Number of Customers [1]	Normalized Energy (kWh) [1]	Current Base Revenue	Mills Per kWh	Total Adjustments to Base Revenue	Proposed Base Revenue	Mills Per kWh	Percent Change Base to Base Revenue
	Uniform Tariff Rates:									
1	Residential Service	1	397,265	5,003,578,752	$379,933,767	75.93	$15,915,203	$395,848,970	79.11	4.19%
2	Master Metered Mobile Home Park	3	22	5,175,311	$372,612	72.00	$15,609	$388,221	75.01	4.19%
3	Residential Service Energy Watch	4	42	743,939	$55,462	74.55	($424)	$55,038	73.98	(0.76)%
4	Residential Service Time-of-Day	5	74	1,178,608	$87,861	74.55	$3,682	$91,543	77.67	4.19%
5	Small General Service	7	28,351	148,946,670	$14,360,806	96.42	$601,465	$14,962,271	100.45	4.19%
	Large General Service	9	30,562	3,492,140,651	$189,089,747	54.15	$7,919,470	$197,009,217	56.42	4.19%
7	Dusk to Dawn Lighting	15	0	6,562,095	$1,128,744	172.01	$47,270	$1,176,014	179.21	4.19%
8	Large Power Service	19	114	2,040,681,796	$82,872,108	40.61	$3,470,864	$86,342,972	42.31	4.19%
9	Agricultural Irrigation Service	24	16,607	1,679,776,734	$103,066,529	61.36	$4,316,727	$107,383,256	63.93	4.19%
10	Unmetered General Service	40	1,984	16,000,941	$1,062,115	66.38	$44,483	$1,106,598	69.16	4.19%
11	Street Lighting	41	314	23,018,849	$2,786,752	121.06	$116,687	$2,903,439	126.13	4.19%
12	Traffic Control Lighting	42	358	3,477,113	$160,191	46.07	$6,710	$166,901	48.00	4.19%
13	Total Uniform Tariffs		475,693	12,421,281,459	$774,976,694	62.39	$32,457,746	$807,434,440	65.00	4.19%
15	Special Contracts:									
16	Micron	26	1	464,652,076	$16,186,333	34.84	$678,051	$16,864,384	36.29	4.19%
17	J R Simplot	29	1	180,758,797	$5,892,299	32.60	$246,716	$6,139,015	33.96	4.19%
18	DOE	30	1	235,100,000	$7,661,384	32.59	$320,805	$7,982,189	33.95	4.19%
19	Hoku - Block 1	32	1	370,006,219	$24,204,343	65.42	$0	$24,204,343	65.42	0.00%
20	Hoku - Block 2	32		197,100,000	$7,084,007	35.94	$296,674	$7,380,681	37.45	4.19%
21	Total Special Contracts		4	1,447,617,092	$61,028,366	42.16	$1,542,246	$62,570,612	43.22	2.53%
23	Total Idaho Retail Sales		475,697	13,868,898,551	$836,005,060	60.28	$33,999,992	$870,005,052	62.73	4.07%

(1) 2011 Test Year Stipulated Energy

Exhibit No. 2
Case No. IPC-E-11-08
Settlement Stipulation, IPC
Page 1 of 2

Exhibit No. 101
Case No. IPC-E-11-8
R. Lobb, Staff
10/07/11 Page 23 of 53

Idaho Power Company
Calculation of Revenue Impact
State of Idaho
2011 GRC Stipulation Funding
Effective January 1, 2012

Summary of Revenue Impact - Rates 9, 19, and 24 Distribution Level Detail

Line No	Tariff Description	Rate Sch. No.	Average Number of Customers (1)	Normalized Energy (kWh) (1)	Current Base Revenue	Mills Per kWh	Adjustments to Base Revenue	Proposed Base Revenue	Mills Per kWh	Percent Change Base to Base Revenue
	Uniform Tariff Rates:									
1	Large General Secondary	9S	30,381	3,090,096,514	$170,596,798	55.21	$7,144,934	$177,741,732	57.52	4.19%
2	Large General Primary	9P	179	399,555,397	$18,377,818	46.00	$769,714	$19,147,532	47.92	4.19%
3	Large General Transmission	9T	2	2,488,740	$115,131	46.26	$4,822	$119,953	48.20	4.19%
4	Total Schedule 9		30,562	3,492,140,651	$189,089,747	54.15	$7,919,470	$197,009,217	56.42	4.19%
6	Large Power Secondary	19S	1	7,166,303	$327,471	45.70	$13,713	$341,184	47.61	4.19%
7	Large Power Primary	19P	110	1,990,012,782	$80,894,078	40.65	$3,387,981	$84,282,059	42.35	4.19%
8	Large Power Transmission	19T	3	43,502,711	$1,650,559	37.94	$69,170	$1,719,729	39.53	4.19%
9	Total Schedule 19		114	2,040,681,796	$82,872,108	40.61	$3,470,864	$86,342,972	42.31	4.19%
11	Irrigation Secondary	24S	16,607	1,679,776,734	$103,066,529	61.36	$4,316,727	$107,383,256	63.93	4.19%
12	Irrigation Transmission	24T	0	0	$0	0.00	$0	$0	0.00	0.00%
13	Total Schedule 24		16,607	1,679,776,734	$103,066,529	61.36	$4,316,727	$107,383,256	63.93	4.19%

(1) 2011 Test Year Stipulated Energy

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-11-08

IDAHO POWER COMPANY

EXHIBIT NO. 3

Idaho Power Company
Calculation of Revenue Impact
State of Idaho
2011 GRC Stipulation Funding
Effective January 1, 2012

Residential Service
Schedule 1

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	Service Charge	4,767,186	$4.00	$19,068,743	$5.00	$23,835,929	$4,767,186	25.00%
2	Mininum Charge	38,143	$2.00	$76,287	$2.00	$76,287	$0	0.00%
3	Energy Blocks							
4	Summer							
	0-800 kWh	795,083,065	0.071026	$56,471,570	0.073940	$58,788,442	$2,316,872	4.10%
6	801-2000 kWh	356,175,288	0.086530	$30,819,848	0.090081	$32,084,626	$1,264,778	4.10%
7	Over 2000 kWh	62,520,889	0.103836	$6,491,919	0.108098	$6,758,383	$266,464	4.10%
8	Non-Summer							
9	0-800 kWh	2,242,884,746	0.066259	$148,611,300	0.068294	$153,175,571	$4,564,271	3.07%
10	801-2000 kWh	1,120,433,597	0.073621	$82,487,442	0.075884	$85,022,983	$2,535,541	3.07%
11	Over 2000 kWh	426,481,167	0.084662	$36,106,749	0.084662	$36,106,749	$0	0.00%
12	Total Energy	5,003,578,752		$360,988,828		$371,936,754	$10,947,926	3.03%
13	Total Energy Revenue at Stipulated Energy and current rates			$360,988,828				
14	Reconciling adjustment to stipulated energy revenue			($1,224,368)				
15	Originally filed Total Energy Revenue			$359,764,460				
16	Normalizing Revenue Adjustment accepted in Stipulation			$1,024,277				
17	Revised Total Energy Revenue			$360,788,737				
18	Total Revenue			$379,933,767		$395,848,970	$15,915,203	4.19%

Idaho Power Company
Calculation of Revenue Impact
State of Idaho
2011 GRC Stipulation Funding
Effective January 1, 2012

Master Metered Mobile Home Park
Residential Service
Schedule 3

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	Service Charge	264.0	$4.00	$1,056	$5.00	$1,320	$264	25.00%
2	Mininum Charge	0.0	$2.00	$0	$2.00	$0	$0	0.00%
3	Energy Charge							
4	Total Energy	5,175,311	0.071794	$371,556	0.074759	$386,901	$15,345	4.13%
5	Total Revenue			$372,612		$388,221	$15,609	4.19%

Idaho Power Company
Calculation of Revenue Impact
State of Idaho
2011 GRC Stipulation Funding
Effective January 1, 2012

Residential Service - Energy Watch Program
Schedule 4

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	Service Charge	510	$4.00	$2,038	$5.00	$2,548	$510	25.02%
2	Mininum Charge	1	$2.00	$1	$2.00	$1	$0	0.00%
3	Energy Charge							
4	Summer							
	Energy Watch Hours	606	0.200000	$121	0.400000	$242	$121	100.00%
6	All other hours	148,289	0.073366	$10,879				
7	Non-Summer							
8	0-800 kWh	303,287	0.066259	$20,095				
9	801-2000 kWh	214,924	0.073621	$15,823				
10	Over 2000 kWh	76,833	0.084662	$6,505				
11	Total Energy	743,939		$53,423				
12	Proposed Energy Charge							
13	Summer							
14	On-Peak	53,384			0.108095	$5,771	$1,854	47.35%
15	Off-Peak	94,905			0.059602	$5,657	($1,306)	(18.75)%
16	Non-Summer							
17	Mid-Peak	285,621			0.078344	$22,377	$2,014	9.89%
18	Off-Peak	309,423			0.059602	$18,442	($3,618)	(16.40)%
19	Total Energy	743,939				$52,489	($934)	(1.75)%
12	Total Revenue			$55,462		$55,038	($424)	(0.76)%

Idaho Power Company
Calculation of Revenue Impact
State of Idaho
2011 GRC Stipulation Funding
Effective January 1, 2012

Residential Service - Time-Of-Day Program
Schedule 5

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	Service Charge	882	$4.00	$3,528	$5.00	$4,410	$882	25.00%
2	Mininum Charge	1	$2.00	$2	$2.00	$2	$0	0.00%
3	Current Energy Charge							
4	Summer							
	On-Peak	72,090	0.106215	$7,657				
6	Mid-Peak	42,914	0.078146	$3,354				
7	Off-Peak	136,937	0.058565	$8,020				
8	Non-Summer							
9	0-800 kWh	522,886	0.066259	$34,646				
10	801-2000 kWh	319,863	0.073621	$23,549				
11	Over 2000 kWh	83,918	0.084662	$7,105				
12	Total Energy	1,178,608		$84,331				
13	Proposed Energy Charge							
14	Summer							
15	On-Peak	90,699			0.113500	$10,294	$1,183	12.98%
16	Off-Peak	161,243			0.062582	$10,091	$172	1.73%
17	Non-Summer							
18	Mid-Peak	444,800			0.082261	$36,590	$5,246	16.74%
19	Off-Peak	481,866			0.062582	$30,156	($3,800)	(11.19)%
20	Total Energy	1,178,608				$87,131	$2,800	3.32%
21	Total Revenue			$87,861		$91,543	$3,682	4.19%

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Small General Service
Schedule 7

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	Service Charge	340,208.4	$4.00	$1,360,834	$5.00	$1,701,042	$340,208	25.00%
2	Mininum Charge	1,100.3	$2.00	$2,201	$2.00	$2,201	$0	0.00%
3	Energy Charge							
4	Summer							
	0-300 kWh	16,880,841	0.083075	$1,402,376	0.084744	$1,430,550	$28,174	2.01%
6	Over 300 kWh	20,872,104	0.098911	$2,064,481	0.102030	$2,129,581	$65,100	3.15%
7	Summer Energy	37,752,945		$3,466,857		$3,560,131	$93,274	2.69%
8	Non-Summer							
9	0-300 kWh	49,222,574	0.083075	$4,089,165	0.084744	$4,171,318	$82,153	2.01%
10	Over 300 kWh	61,971,152	0.087811	$5,441,749	0.089196	$5,527,579	$85,830	1.58%
11	Non-Summer Energy	111,193,725		$9,530,914		$9,698,897	$167,983	1.76%
12	Total Energy	148,946,670		$12,997,771		$13,259,028	$261,257	2.01%
13	Total Revenue			$14,360,806		$14,962,271	$601,465	4.19%

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Large General Service
Schedule 9 Secondary Service

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	Service Charge	364,571.4	$14.43	$5,260,765	$16.00	$5,833,142	$572,377	10.88%
2	Mininum Charge	593.9	5.00	$2,969	5.00	$2,969	$0	0.00%
3	Basic Charge							
4	Summer and Non-Summer							
	0-20 kW	5,426,656	0.00	$0	0.00	$0	$0	0.00%
6	Over 20 kW	7,781,165	0.78	$6,069,309	0.95	$7,392,107	$1,322,798	21.79%
7	Total Basic Charge	13,207,821		$6,069,309		$7,392,107	$1,322,798	21.79%
8	Demand Charge							
9	0-20 kW							
10	Summer and Non-Summer	4,647,531	$0.00	$0	$0.00	$0	$0	0.00%
11	Over 20 kW							
12	Summer	1,501,856	4.61	$6,923,555	5.59	$8,395,373	$1,471,818	21.26%
13	Non-Summer	3,965,879	3.68	$14,594,435	4.10	$16,260,105	$1,665,670	11.41%
14	Total Demand	10,115,266		$21,517,990		$24,655,478	$3,137,488	14.58%
15	Energy Charge							
16	Summer							
17	0-2000 kWh	150,689,955	0.090122	$13,580,480	0.091385	$13,770,802	$190,322	1.40%
18	Over 2000 kWh	679,918,294	0.038639	$26,271,363	0.039184	$26,641,918	$370,555	1.41%
19	Non-Summer							
20	0-2000 kWh	435,820,869	0.080407	$35,043,049	0.081682	$35,598,720	$555,671	1.59%
21	Over 2000 kWh	1,823,667,397	0.034464	$62,850,873	0.035010	$63,846,596	$995,723	1.58%
22	Total Energy	3,090,096,514		$137,745,765		$139,858,036	$2,112,271	1.53%
23	Total Revenue			$170,596,798		$177,741,732	$7,144,934	4.19%

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Large General Service
Schedule 9 Primary Service

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	Service Charge	2,145.7	$247.27	$530,567	$285.00	$611,525	$80,958	15.26%
2	Mininum Charge	0.2	10.00	$2	10.00	$2	$0	0.00%
3	Basic Charge							
4	Total Basic Charge	1,203,758	1.12	$1,348,209	1.18	$1,420,435	$72,226	5.36%
5	Demand Charge							
6	Summer	257,168	4.24	$1,090,391	4.75	$1,221,547	$131,156	12.03%
7	Non-Summer	723,117	3.91	$2,827,386	4.16	$3,008,165	$180,779	6.39%
8	Total Demand	980,284		$3,917,777		$4,229,712	$311,935	7.96%
9	On-Peak Summer	239,388	0.79	$189,117	0.88	$210,661	$21,544	11.39%
10	Energy Charge							
11	On-peak	29,263,155	0.037953	$1,110,625	0.038710	$1,132,777	$22,152	1.99%
12	Mid-peak	45,650,239	0.034511	$1,575,435	0.035193	$1,606,569	$31,134	1.98%
13	Off-peak	29,496,998	0.032254	$951,396	0.032892	$970,215	$18,819	1.98%
14	Summer Energy Charge	104,410,392		$3,637,456		$3,709,561	$72,105	1.98%
15	Mid-Peak	184,186,793	0.030127	$5,548,996	0.030853	$5,682,715	$133,719	2.41%
16	Off-peak	110,958,212	0.028891	$3,205,694	0.029587	$3,282,921	$77,227	2.41%
17	Non-Summer Energy Chrge	295,145,005		$8,754,690		$8,965,636	$210,946	2.41%
18	Total Energy Charge	399,555,397		$12,392,146		$12,675,197	$283,051	2.28%
19	Total Revenue			$18,377,818		$19,147,532	$769,714	4.19%

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Large General Service
Schedule 9 Transmission

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	Service Charge	24.0	$247.27	$5,934	$285.00	$6,840	$906	15.27%
2	Mininum Charge	0	10.00	$0	10.00	$0	$0	0.00%
3	Basic Charge							
4	Total Basic Charge	9,861	0.58	$5,719	0.63	$6,212	$493	8.62%
5	Demand Charge							
6	Summer	1,999	4.06	$8,116	4.47	$8,935	$819	10.09%
7	Non-Summer	4,800	3.76	$18,049	4.00	$19,201	$1,152	6.38%
8	Total Demand Charge	6,799		$26,165		$28,136	$1,971	7.53%
9	On-Peak Summer	1,704	0.79	$1,346	0.88	$1,500	$154	11.44%
10	Energy Charge							
11	On-peak	154,179	0.037318	$5,754	0.037902	$5,844	$90	1.56%
12	Mid-peak	270,753	0.034016	$9,210	0.034528	$9,349	$139	1.51%
13	Off-peak	220,243	0.031841	$7,013	0.032309	$7,116	$103	1.47%
14	Summer Energy Charge	645,175		$21,977		$22,309	$332	1.51%
15	Mid-Peak	1,048,594	0.029771	$31,218	0.030307	$31,780	$562	1.80%
16	Off-peak	794,971	0.028645	$22,772	0.029153	$23,176	$404	1.77%
17	Non-Summer Energy Chrge	1,843,565		$53,990		$54,956	$966	1.79%
18	Total Energy Charge	2,488,740		$75,967		$77,265	$1,298	1.71%
19	Total Revenue			$115,131		$119,953	$4,822	4.19%

Idaho Power Company
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Dusk-to-Dawn Customer Lighting
Schedule 15

Line No	Description	(0) Lamps	(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	Lamps								
2	100-Watt Sodium Vapor (A)	99,882	3,895,350	7.20	$719,150	8.56	$854,990	$135,840	18.89%
3	200-Watt Sodium Vapor (A)	8,395	621,210	11.65	$97,802	10.24	$85,965	$(11,837)	(12.10)%
4	400-Watt Sodium Vapor (A)	1,287	202,052	18.67	$24,028	14.00	$18,018	$(6,010)	(25.01)%
5	200-Watt Sodium Vapor (D)	9,339	691,092	14.17	$132,334	12.39	$115,710	$(16,624)	(12.56)%
	400-Watt Sodium Vapor (D)	5,393	846,614	21.18	$114,224	14.68	$79,169	$(35,055)	(30.69)%
7	400-Watt Metal Halide (D)	785	121,698	23.68	$18,589	13.44	$10,550	$(8,039)	(43.25)%
8	1000-Watt Metal Halide(D)	509	184,079	43.20	$21,989	21.58	$10,984	$(11,005)	(50.05)%
9	Total	125,590	6,562,095		1,128,116		1,175,386	$47,270	4.19%
10	Mininum Charge	209.5		3.00	628	3.00	628	$0	0.00%
11	Total Revenue				$1,128,744		$1,176,014	$47,270	4.19%

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Large Power Service
Schedule 19 Secondary

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	Service Charge	12.0	$14.38	$173	$39.00	$468	$295	170.52%
2	Basic Charge							
3	Total Basic Charge	16,027	0.78	$12,501	0.86	$13,783	$1,282	10.26%
	Demand Charge							
5	Summer	3,132	3.92	$12,279	5.55	$17,385	$5,106	41.58%
6	Non-Summer	11,422	3.67	$41,919	3.97	$45,346	$3,427	8.18%
7	Total Demand Charge	14,555		$54,198		$62,731	$8,533	15.74%
8	On-Peak Summer	2,822	0.79	$2,230	0.95	$2,681	$451	20.22%
9	Energy Charge							
10	On-peak	388,291	0.051863	$20,138	0.052765	$20,488	$350	1.74%
11	Mid-peak	678,748	0.039741	$26,974	0.040343	$27,383	$409	1.52%
12	Off-peak	474,050	0.034555	$16,381	0.035030	$16,606	$225	1.37%
13	Summer Energy Charge	1,541,089		$63,493		$64,477	$984	1.55%
14	Mid-Peak	3,315,662	0.036612	$121,393	0.037041	$122,815	$1,422	1.17%
15	Off-peak	2,309,552	0.031817	$73,483	0.032140	$74,229	$746	1.02%
16	Non-Summer Energy Chrge	5,625,214		$194,876		$197,044	$2,168	1.11%
17	Total Energy Charge	7,166,303		$258,369		$261,521	$3,152	1.22%
18	Total Revenue			$327,471		$341,184	$13,713	4.19%

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Large Power Service
Schedule 19 Primary

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	Service Charge	1,316.00	$247.27	$325,407	$299.00	$393,484	$68,077	20.92%
2	Basic Charge							
3	Total Basic Charge	4,743,270	1.12	$5,312,462	1.18	$5,597,058	$284,596	5.36%
	Demand Charge							
5	Summer	1,051,491	4.24	$4,458,320	5.65	$5,940,922	$1,482,602	33.25%
6	Non-Summer	3,024,950	3.91	$11,827,555	4.18	$12,644,292	$816,737	6.91%
7	Total Demand Charge	4,076,441		$16,285,875		$18,585,214	$2,299,339	14.12%
8	On-Peak Summer	996,766	0.79	$787,445	0.89	$887,122	$99,677	12.66%
9	Energy Charge							
10	On-peak	130,957,346	0.041819	$5,476,505	0.042304	$5,540,020	$63,515	1.16%
11	Mid-peak	217,542,182	0.031856	$6,930,024	0.032128	$6,989,195	$59,171	0.85%
12	Off-peak	160,591,605	0.027692	$4,447,103	0.027871	$4,475,849	$28,746	0.65%
13	Summer Energy Charge	509,091,132		$16,853,632		$17,005,064	$151,432	0.90%
14	Mid-Peak	871,843,728	0.029490	$25,710,672	0.029861	$26,034,126	$323,454	1.26%
15	Off-peak	609,077,921	0.025643	$15,618,585	0.025908	$15,779,991	$161,406	1.03%
16	Non-Summer Energy Chrge	1,480,921,650		$41,329,257		$41,814,117	$484,860	1.17%
17	Total Energy Charge	1,990,012,782		$58,182,889		$58,819,181	$636,292	1.09%
18	Total Revenue			$80,894,078		$84,282,059	$3,387,981	4.19%

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Large Power Service
Schedule 19 Transmission

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	Service Charge	36.0	$247.27	$8,902	$299.00	$10,764	$1,862	20.92%
2	Basic Charge							
3	Total Basic Charge	89,644	0.58	$51,994	0.65	$58,269	$6,275	12.07%
	Demand Charge							
5	Summer	21,779	4.06	$88,423	5.48	$119,349	$30,926	34.98%
6	Non-Summer	56,762	3.76	$213,426	4.06	$230,455	$17,029	7.98%
7	Total Demand Charge	78,541		$301,849		$349,804	$47,955	15.89%
8	On-Peak Summer	21,120	0.79	$16,685	0.89	$18,797	$2,112	12.66%
9	Energy Charge							
10	On-peak	3,208,853	0.041479	$133,100	0.041668	$133,706	$606	0.46%
11	Mid-peak	5,064,999	0.031746	$160,793	0.031861	$161,376	$583	0.36%
12	Off-peak	4,164,156	0.027605	$114,952	0.027649	$115,135	$183	0.16%
13	Summer Energy Charge	12,438,008		$408,845		$410,217	$1,372	0.34%
14	Mid-peak	18,219,363	0.029341	$534,574	0.029692	$540,969	$6,395	1.20%
15	Off-peak	12,845,340	0.025512	$327,710	0.025761	$330,909	$3,199	0.98%
16	Non-Summer Energy Charge	31,064,703		$862,284		$871,878	$9,594	1.11%
17	Total Energy Charge	43,502,711		$1,271,129		$1,282,095	$10,966	0.86%
18	Total Revenue			$1,650,559		$1,719,729	$69,170	4.19%

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Agricultural Irrigation Service
Schedule 24 Secondary

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	Bills-In Season	67,439.1	$18.18	$1,226,043	$22.00	$1,483,660	$257,617	21.01%
2	Bills-Out Season	131,850.0	3.46	$456,201	3.50	$461,475	$5,274	1.16%
3	Mininum Charge	648.5	1.50	$973	1.50	$973	$0	0.00%
4	Demand Charge							
	Total In-Season	3,688,584	5.65	$20,840,499	6.54	$24,123,339	$3,282,840	15.75%
6	Total Out-Season	1,794,016	0.00	$0	0.00	$0	$0	0.00%
7	Total kW	5,482,600		$20,840,499		$24,123,339	$3,282,840	15.75%
8	Energy Charge							
9	First 164 kWh per kW	597,508,971	0.046851	$27,993,893	0.048214	$28,808,298	$814,405	2.91%
10	All Other kWh In-Season	776,574,362	0.045485	$35,322,485	0.045485	$35,322,485	$0	0.00%
11	Total Out-Season	305,693,401	0.056352	$17,226,435	0.056210	$17,183,026	($43,409)	(0.25)%
12	Total Energy	1,679,776,734		$80,542,813		$81,313,809	$770,996	0.96%
13	Total Revenue			$103,066,529		$107,383,256	$4,316,727	4.19%

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Agricultural Irrigation Service
Schedule 24 Transmission

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	Bills-In Season	0.0	$248.22	$0	$299.00	$0	$0	0.00%
2	Bills-Out Season	0.0	3.46	$0	3.50	$0	$0	0.00%
3	Demand Charge							
4	Total In-Season	0	5.32	$0	6.16	$0	$0	0.00%
	Total Out-Season	0	0.00	$0	0.00	$0	$0	0.00%
6	Total kW	0		$0		$0	$0	0.00%
7	Energy Charge							
8	First 164 kWh per kW	0	0.043653	$0	0.044923	$0	$0	0.00%
9	All Other kWh In-Season	0	0.042382	$0	0.042382	$0	$0	0.00%
10	Total Out-Season	0	0.052509	$0	0.052377	$0	$0	0.00%
11	Total Energy	0		$0		$0	$0	0.00%
12	Total Revenue			$0		$0	$0	0.00%

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Unmetered General Service
Schedule 40

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	Number of Bills	23,808.0	0.00	$0	0.00	$0	$0	0.00%
2	Mininum Charge	942.3	$1.50	$1,413	$1.50	$1,413	$0	0.00%
3	Total Energy	16,000,941	0.06629	$1,060,702	0.06907	$1,105,185	$44,483	4.19%
	Total Revenue			$1,062,115		$1,106,598	$44,483	4.19%

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Street Lighting Service
Schedule 41

Summary

Line No	Description	(1) Annual Lamps	(2) Current Base Rate	(3) Current Base Revenue	(4) Proposed Base Rate	(5) Proposed Base Revenue	(6) Revenue Difference	(7) Percent Change
1	A - Company-Owned, Non-Metered, Maintenance			$1,616,310		$2,070,882	$454,572	28.12%
2	B - Customer-Owned, Non-Metered, Maintenance			$989,037		$711,084	($277,953)	(28.10)%
3	BM - Customer-Owned, Metered, Maintenance			$5,200		$3,217	($1,983)	(38.13)%
4	C - Customer-Owned, Non-Metered, No Maintenance			$0		$0	$0	0.00%
5	CM - Customer-Owned, Metered, No Maintenance			$176,205		$118,256	($57,949)	(32.89)%
6	Total Bills	3,768						
7	Total kWh	23,018,849						
8	Total Revenue			$2,786,752		$2,903,439	$116,687	4.19%

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Schedule 41 - Street Lighting Service (cont'd)

Line No	Description	(1) Annual Lamps	(2) Current Base Rate	(3) Current Base Revenue	(4) Proposed Base Rate	(5) Proposed Base Revenue	(6) Revenue Difference	(7) Percent Change
1	**A - Company-Owned, Non-Metered, Maintenance**							
2	Sodium Vapor							
3	70-Watt	452	$8.71	$3,939	$10.34	$4,676	$737	18.71%
4	100-Watt	176,809	$7.83	$1,384,416	$9.84	$1,739,802	$355,386	25.67%
5	200-Watt	21,917	$9.17	$200,979	$13.30	$291,496	$90,517	45.04%
6	250-Watt	1,179	$10.37	$12,222	$14.51	$17,101	$4,879	39.92%
7	400-Watt	814	$13.06	$10,625	$16.60	$13,505	$2,880	27.11%
8	Total Sodium Vapor	201,170		$1,612,181		$2,066,580	$454,399	28.19%
9	Non-Metered - Variable Energy Use	62,280	0.066290	$4,129	0.069070	$4,302	$173	4.19%
10	A - Company-Owned, Non-Metered, Maintenance			$1,616,310		$2,070,882	$454,572	28.12%

Idaho Power Company
Calculation of Revenue Impact
State of Idaho
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Schedule 41 - Street Lighting Service (cont'd)

Line No	Description	(1) Annual Lamps	(2) Current Base Rate	(3) Current Base Revenue	(4) Proposed Base Rate	(5) Proposed Base Revenue	(6) Revenue Difference	(7) Percent Change
1	**B - Customer-Owned, Non-Metered, Maintenance**							
2	Mercury Vapor							
3	175-Watt	96	$6.43	$619	$4.07	$392	($227)	(36.67)%
4	400-Watt	70	10.16	$713	7.88	$553	($160)	(22.44)%
5	Total Mercury Vapor	166		$1,332		$945	($387)	(29.05)%
6	Sodium Vapor							
7	70-Watt	60	3.74	$225	2.54	$153	($72)	(32.00)%
8	100-Watt	129,462	4.24	$548,918	2.86	$370,260	($178,658)	(32.55)%
9	200-Watt	5,218	5.88	$30,684	4.30	$22,439	($8,245)	(26.87)%
10	250-Watt	41,947	6.99	$293,210	5.38	$225,675	($67,535)	(23.03)%
11	400-Watt	11,769	9.72	$114,394	7.76	$91,327	($23,067)	(20.16)%
12	Total Sodium Vapor	188,456		$987,431		$709,854	($277,577)	(28.11)%
13	Non-Metered - Variable Energy Use	4,128	0.066290	$274	0.069070	$285	$11	4.01%
14	B - Customer-Owned, Non-Metered, Maintenance			$989,037		$711,084	($277,953)	(28.10)%
15	**BM - Customer-Owned, Metered, Maintenance**							
16	Mercury Vapor							
17	175-Watt	0	1.96	$0	1.22	$0	$0	0.00%
18	400-Watt	0	2.03	$0	1.23	$0	$0	0.00%
19	Total Mercury Vapor	0		$0		$0	$0	0.00%
20	Sodium Vapor							
21	70-Watt	0	2.53	$0	1.28	$0	$0	0.00%
22	100-Watt	0	2.23	$0	1.18	$0	$0	0.00%
23	200-Watt	0	2.31	$0	1.17	$0	$0	0.00%
24	250-Watt	192	2.23	$429	1.28	$246	($183)	(42.66)%
25	400-Watt	230	2.29	$526	1.28	$294	($232)	(44.11)%
26	Total Lamp Charges	422		$955		$540	($415)	(43.46)%
27	Meter Charge	112	8.57	$960	3.36	$376	($584)	(60.83)%
28	Energy Charge							
29	Per kWh	55,318	0.059385	$3,285	0.041604	$2,301	($984)	(29.95)%
30	BM - Customer-Owned, Metered, Maintenance			$5,200		$3,217	($1,983)	(38.13)%

State of Idaho
2011 GRC Stipulation Funding
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Schedule 41 - Street Lighting Service (cont'd)

Line No	Description	(1) Annual Lamps	(2) Current Base Rate	(3) Current Base Revenue	(4) Proposed Base Rate	(5) Proposed Base Revenue	(6) Revenue Difference	(7) Percent Change
1	**C - Customer-Owned, Non-Metered, No Maintenance**							
2	Energy Charge							
3	Per kWh	0	0.059385	$0	0.041604	$0	$0	0.00%
4	C - Customer-Owned, Non-Metered, No Maintenance			$0		$0	$0	0.00%
5	**CM - Customer-Owned, Metered, No Maintenance**							
6	Meter Charge	1,963	8.57	$16,823	3.36	$6,596	($10,227)	(60.79)%
7	Energy Charge							
8	Per kWh	2,683,882	0.059385	$159,382	0.041604	$111,660	($47,722)	(29.94)%
9	CM - Customer-Owned, Metered, No Maintenance			$176,205		$118,256	($57,949)	(32.89)%

Idaho Power Company
Calculation of Revenue Impact
State of Idaho
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Traffic Control Lighting
Schedule 42

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	No. of Billings	4,296.0	0.00		0.00			
2	Traffic Lamps	3,477,113	$0.04607	$160,191	$0.04800	$166,901	$6,710	4.19%
3	Total Revenue			$160,191		$166,901	$6,710	4.19%

Idaho Power Company
Calculation of Revenue Impact
State of Idaho
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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	$1.55	$1,116,000	$43,200	4.03%
2	Billed kW	673,510.0	$9.75	$6,566,723	$10.16	$6,842,862	$276,139	4.21%
3	Excess Demand kW	0	0.276	$0	0.288	$0	$0	0.00%
4	Billed kWh	464,652,076	0.018394	$8,546,810	0.019166	$8,905,522	$358,712	4.20%
5	Total Revenue			$16,186,333		$16,864,384	$678,051	4.19%

Idaho Power Company
Calculation of Revenue Impact
State of Idaho
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Effective January 1, 2012

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	$2.13	$639,000	$27,000	4.41%
2	Daily Excess Demand kW	0	0.276	$0	0.288	$0	$0	0.00%
3	Demand (kW)	278,318	6.97	$1,939,876	7.26	$2,020,589	$80,713	4.16%
4	Energy (kWh)	180,758,797	0.018480	$3,340,423	0.019249	$3,479,426	$139,003	4.16%
5	Total Revenue			$5,892,299		$6,139,015	$246,716	4.19%

Idaho Power Company
Calculation of Revenue Impact
State of Idaho
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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	$7.87	$3,137,013	$127,553	4.24%
2	Total Energy	235,100,000	0.019787	$4,651,924	0.020609	$4,845,176	$193,252	4.15%
3	Total Revenue			$7,661,384		$7,982,189	$320,805	4.19%

Idaho Power Company
Calculation of Revenue Impact
State of Idaho
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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	$4.82	$1,446,000	$57,000	4.10%
4	Second Block Energy	197,100,000	0.028894	$5,695,007	0.030110	$5,934,681	$239,674	4.21%
	Additional Min. Energy Revenue	0		$0		$0	$0	0.00%
6	Excess Demand Charges							
7	Daily Excess Demand	0	$0.57	$0	$0.59	$0	$0	0.00%
8	Monthly excess Demand	0	$5.71	$0	$5.95	$0	$0	0.00%
9	Excess Energy Charge	0	0.088647	$0	0.092361	$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		$7,380,681	$296,674	4.19%
12	Total Revenue			$31,288,350		$31,585,024	$296,674	0.95%

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-11-08

IDAHO POWER COMPANY

EXHIBIT NO. 4

IDAHO POWER COMPANY
Development of Load Change Adjustment Rate
Table I
Derivation of Energy-Related Generation Function Revenue Requirement

	A	B	C	D	E	F
	Rate Base (1)	Expenses	Income Tax	A&G Expense Exclusion	Other Revenue	Subsidiary Income
Source	Ex 32, L. 12	Ex 32, L. 72 & 114	Table II, Col. E	See Note 2	See Note 3	Ex. 35, L. 35
Generation Function Energy-Related	489,852,041	362,209,697	4,256,640	20,103,847	112,150,644	6,323,218

	G	H	I	J	K
	Current Return	Desired Return	Revenue Short-Fall	Tax Gross-Up	Total Revenue Requirement
Source	A x 6.984% (4)	A x 7.863% (5)	H-G	I x 1.642 - I	B+C-D-E-F+H+J
Generation Function Energy-Related	34,211,672	38,517,066	4,305,394	2,764,063	$269,169,757

Notes:
(1) Classified as energy-related based on an Idaho jurisdictional load factor of 53.88%
(2) Exhibit 31, Lines 480-540. The portion of the overall A&G exclusion associated with the energy-related generation function
(3) Exhibit 32, Line 132, plus Hoku first block energy sales revenues, Exhibit 35, Line 14
(4) Exhibit 35, Line 38
(5) Exhibit 35, Line 43

IDAHO POWER COMPANY
Development of Load Change Adjustment Rate
Table II
Allocation of Income Taxes to Energy-Related Generation Function

	A	B	C	D	E
	Total Federal Income Tax	Total State Income Tax	Energy-Related Generation Function Rate Base	Total Rate Base	Allocated Income Taxes
Source	Ex 35, L. 28	Ex 35, L. 29	Ex. 32, L. 12	Ex 32, L. 60	(A+B) x (C÷D)
Generation Function Energy-Related	14,299,801	6,172,175	489,852,041	2,355,904,909	4,256,640

IDAHO POWER COMPANY
Development of Load Change Adjustment Rate
Table III
Final Rate Determination

	A	B	C
	Energy-Related Generation Function Revenue Requirement	2011 Test Year Idaho Jurisdictional Load at Generation Level (MWh)	Load Change Adjustment Rate ($/MWh)
Source	Table I, Col. K	Ex. 37, L. 106	A ÷ B
Generation Function Energy-Related	$269,169,757	14,822,063	$18.16

Monthly Billing Comparison
Settlement Stipulation
Case No. IPC-E-11-08

Small General Service, 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	Stipulated Revenue	Percent Difference	Current Revenue	Stipulated Revenue	Percent Difference	Current Revenue	Stipulated Revenue	Percent Difference
1	100	12.31	13.47	9.48%	12.31	13.47	9.48%	12.31	13.47	9.42%
2	200	20.62	21.95	6.47%	20.62	21.95	6.47%	20.62	21.95	6.45%
3	300	28.92	30.42	5.19%	28.92	30.42	5.19%	28.92	30.42	5.19%
4	400	38.81	40.63	4.67%	37.70	39.34	4.35%	37.98	39.66	4.42%
5	500	48.70	50.83	4.36%	46.48	48.26	3.82%	47.04	48.90	3.95%
6	600	58.60	61.03	4.16%	55.27	57.18	3.47%	56.10	58.14	3.64%
7	700	68.49	71.24	4.01%	64.05	66.10	3.21%	65.16	67.39	3.42%
8	800	78.38	81.44	3.90%	72.83	75.02	3.01%	74.22	76.63	3.25%
9	900	88.27	91.64	3.82%	81.61	83.94	2.86%	83.27	85.87	3.12%
10	1,000	98.16	101.84	3.75%	90.39	92.86	2.73%	92.33	95.11	3.01%
11	1,100	108.05	112.05	3.70%	99.17	101.78	2.63%	101.39	104.35	2.92%
12	1,200	117.94	122.25	3.65%	107.95	110.70	2.54%	110.45	113.59	2.84%
13	1,300	127.83	132.45	3.61%	116.73	119.62	2.47%	119.51	122.83	2.78%
14	1,400	137.72	142.66	3.58%	125.51	128.54	2.41%	128.57	132.07	2.72%
15	1,500	147.62	152.86	3.55%	134.30	137.46	2.36%	137.63	141.31	2.67%
16	2,000	197.07	203.87	3.45%	178.20	182.06	2.16%	182.92	187.51	2.51%
17	2,500	246.53	254.89	3.39%	222.11	226.65	2.05%	228.21	233.71	2.41%
18	3,000	295.98	305.90	3.35%	266.01	271.25	1.97%	273.50	279.92	2.35%
19	4,000	394.89	407.93	3.30%	353.82	360.45	1.87%	364.09	372.32	2.26%
20	5,000	493.80	509.96	3.27%	441.63	449.64	1.81%	454.68	464.72	2.21%

Monthly Billing Comparison
Settlement Stipulation
Case No. IPC-E-11-08

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	Stipulated Revenue	Percent Difference	Current Revenue	Stipulated Revenue	Percent Difference	Current Revenue	Stipulated Revenue	Percent Difference
1	0	4.00	5.00	25.00%	4.00	5.00	25.00%	4.00	5.00	25.00%
2	100	11.10	12.39	11.62%	10.63	11.83	11.29%	10.75	11.97	11.35%
3	200	18.21	19.79	8.68%	17.25	18.66	8.17%	17.49	18.94	8.29%
4	300	25.31	27.18	7.39%	23.88	25.49	6.74%	24.24	25.91	6.89%
5	400	32.41	34.58	6.70%	30.50	32.32	5.97%	30.98	32.89	6.17%
6	500	39.51	41.97	6.23%	37.13	39.15	5.44%	37.73	39.86	5.65%
7	600	46.62	49.36	5.88%	43.76	45.98	5.07%	44.48	46.83	5.28%
8	700	53.72	56.76	5.66%	50.38	52.81	4.82%	51.22	53.80	5.04%
9	800	60.82	64.15	5.48%	57.01	59.64	4.61%	57.96	60.77	4.85%
10	900	69.47	73.16	5.31%	64.37	67.23	4.44%	65.65	68.71	4.66%
11	1,000	78.13	82.17	5.17%	71.73	74.82	4.31%	73.33	76.66	4.54%
12	1,050	82.45	86.67	5.12%	75.42	78.61	4.23%	77.18	80.63	4.47%
13	1,100	86.78	91.17	5.06%	79.10	82.41	4.18%	81.02	84.60	4.42%
14	1,200	95.43	100.18	4.98%	86.46	89.99	4.08%	88.70	92.54	4.33%
15	1,300	104.09	109.19	4.90%	93.82	97.58	4.01%	96.39	100.48	4.24%
16	1,400	112.74	118.20	4.84%	101.18	105.17	3.94%	104.07	108.43	4.19%
17	1,500	121.39	127.21	4.79%	108.54	112.76	3.89%	111.75	116.37	4.14%
18	2,000	164.66	172.25	4.61%	145.36	150.70	3.67%	150.19	156.09	3.93%
19	2,500	216.58	226.30	4.49%	187.69	193.03	2.85%	194.91	201.35	3.30%
20	3,000	268.50	280.35	4.41%	230.02	235.36	2.32%	239.64	246.61	2.91%
21	4,000	372.33	388.45	4.33%	314.68	320.02	1.70%	329.09	337.13	2.44%
22	5,000	476.17	496.54	4.28%	399.35	404.69	1.34%	418.56	427.65	2.17%

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS **7TH** DAY OF OCTOBER 2011, SERVED THE FOREGOING **DIRECT TESTIMONY OF RANDY LOBB IN SUPPORT OF THE STIPULATION AND SETTLEMENT,** IN CASE NO. IPC-E-11-08, BY E-MAILING AND MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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