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BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

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

DIRECT TESTIMONY AND EXHIBITS OF

DR. DON READING

ON BEHALF OF

INDUSTRIAL CUSTOMERS OF IDAHO POWER

OCTOBER 24, 2008

INTRODUCTION

Q. **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Don Reading and my business address is Ben Johnson Associates, 6070 Hill Road, Boise, Idaho.

Q. **HAVE YOU PREPARED AN EXHIBIT OUTLINING YOUR QUALIFICATIONS AND BACKGROUND?**

A. Yes. Exhibit 201 serves that purpose.

Q. **WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS CASE?**

A. I have been retained by the Industrial Customers of Idaho Power (ICIP) to review Idaho Power's (IPC, Company) application for authority to increase its rates and charges for electric service. Specifically I examine the Company's rate allocations that are derived from its preferred cost of service (COS) study. I propose changes to Idaho Power's COS that brings cost assignments closer the Company's load profile as a capacity constrained utility rather than as an energy constrained utility. I also address the Company's use of a projected test year and recommend an approach the Commission may take that would satisfy some of the goals sought by the Company while addressing some of the problems inherent with a forecasted test year. I discuss the Company's recommended inclusion of construction work in progress (CWIP) in this case and recommend the Commission reject its inclusion in base rates. I also give a brief update on the status of our virtual peaking discussions with Idaho Power.

<u>**Cost of Service**</u>

Q. DR. READING, TURNING TO YOUR EXAMINATION OF IDAHO POWER'S COST OF SERVICE STUDY -- COULD YOU PLEASE BRIEFLY REVIEW THE COMPANY'S APPROACH?

A. Yes. Staff witness Tatum presents three separate cost of service studies; Base Case, Modified Base Case, and 3 CP/12 CP. The Company's preferred approach, as it was in the last case (IPC-E-07-08), is the 3 CP/12 CP study. This approach is being recommended because the Company believes it is the most effective method of allocating production plant costs consistent with the costs imposed by each given customer class. [Tatum, Di. pages 51,52.]

Q. DO YOU HAVE ANY GENERAL OBSERVATIONS?

A. Yes. I have two general observations. First, Mr. Tatum states that the Base Case is consistent with the "Normalized" method filed in the last rate proceeding. That rate proceeding, IPC-E-07-08, was settled and thus the cost of service study was not litigated in that case. Therefore, when comparing the Company's proposed COS with past filings, the base of comparison should be the last one filed by the Company and approved by the Commission in case No. IPC-E-03-13.

Second, as indicated by Company Exhibit 69, a disproportionate share of the overall 9.89% proposed increase requested by Idaho Power falls on high load factor customers under all three COS cases presented by the Company (irrigation service being the one exception of a low load factor costumer having a significant increase in revenue requirement). The indicated increases for all three studies presented for residential customers range from 2.01% (Base Case) to 3.71% (3 CP/12/ CP). On the other hand, the range of increases for Schedule 19 and the Special Contract customers is 15.21% (Schedule 19, Modified Base Case) to 32.61% (JR Simplot, Base Case).

Q. WHY DO YOU POINT OUT THAT THE COST OF SERVICE STUDY FILED BY THE COMPANY SHOULD LOOK TO CASE IPC-E-03-13 AS THE BASE CASE FOR COMPARISON TO THE CURRENT CASE?

A. As I testified above, Idaho Power's last general rate case was settled. In the Settlement Agreement the parties agreed that the cost of service study filed in that case would not be precedent setting. The Commission recognized that fact in its order approving the settlement:

> The parties also agreed that the underlying cost-of-service model filed by the Company in this proceeding will not constitute precedent in any subsequent general rate case. The parties specifically recognize that any party s failure to specifically object to the Company s cost-of-service analysis in this case will not constitute a waiver in any future general rate case proceeding. [Idaho Public Commission Order 30035, IPC-E-05-28, page 5.]

The COS filed in the last case also allocated the major share of the proposed rate increase to the high load factor customers. A hint of the reason for this disproportionate share for high load factor customers is found in Company witness Brilz IPC-E-05-28 Direct Testimony filed in that case.

Q. **WHAT REASONS DID MS. BRILZ GIVE FOR THE DISPROPORTIONATELY HIGHER ALLOCATIONS TO HIGH LOAD FACTOR CUSTOMERS FOUND IN THE COMPANY'S COST OF SERVICE STUDIES ?**

A. In her filed testimony she stated,

> Since the conclusion of the Company's last general rate case it has been determined that the deficit months of June, July, August, November, and December used in the 2003 marginal cost analysis were primarily determined by firm generation supply acquisition need rater than determination of months in which a peak-hour deficiency occurred. The deficit months of January, May, June, July, August, September, November, and December used in the current marginal cost analysis are directly tied to peak-hour deficiency months identified in the 2004 IRP.

And,

> The use of eight deficit months (January, May, June, July, August, September, November, and December) in the current marginal cost analysis results in weighting factors that attribute more generation capacity cost responsibility to customer classes with usage throughout most of the year. [Direct Testimony, Maggie Brilz, IPC-E-05-28, page 21,22.]

The effect of extending the number of months used in the marginal cost study from 5 to 8 months spreads the costs of generation to customer classes with high use over a greater number of months.

Q. **THE COMPANY HAS INCREASED THE NUMBER OF MONTHS TO WHICH IT IS APPLYING CAPACITY COSTS. WHAT HAVE BEEN THE TRENDS IN THE MARGINAL COST OF CAPACITY AND ENERGY FOR IDAHO POWER SINCE THE IPC-E-03-13 GENERAL RATE CASE?**

A. There have been dramatic shifts in the costs of capacity and energy for the Company in the 5 years since case IPC-E-03-13 was filed. Marginal generation capacity costs have dropped by 45% from $90.71 per KW to $50.00 per KW. The monthly amounts are shown on my Exhibit No. 202. While capacity costs have dropped, marginal power supply costs over the same 5 year period increased dramatically by 114%, from $33.38 to $71.46 per MWh. The increase has been especially large in July and August with currently estimated marginal costs of $99.66 and $81.85 per MWh respectively. My Exhibit 203 displays monthly marginal power supply costs over the last 4 filed general rate cases.

Q. **HOW DO YOU EXPLAIN THE SIGNIFICANT DROP IN MARGINAL CAPACITY COSTS COUPLED WITH THE DRAMATIC INCREASE IN MARGINAL ENERGY COSTS?**

A. It appears to be the function of two interrelated factors. Natural gas prices have increased since the filing of the general rate case in 2003, and the Company has added gas peaking resources. The capacity costs of a gas peaking unit on a per KW basis are relatively lower than other generating resources. The trade off for these lower capacity costs is higher fuel costs and hence higher energy costs. The higher gas prices have also driven the cost of purchasing off system power to higher levels.

Q. IDAHO POWER HAS A RESOURCE STACK WITH MIX OF DIFFERENT TYPES OF RESOURCES. WHAT HAVE BEEN THE CHANGES IN THE COST OF ENERGY ON A NORMALIZED BASIS OVER THE PAST 5 YEARS?

A. As shown on my Exhibit 204, energy costs have increase from a variety of resources. Both Bridger and Valmy, with essentially the same output since 2005, have experienced increased energy production costs by $35 million. The two gas fired units in the Company's resource stack have power supply costs of $81.96 per MWh for Bennett Mountain and $195.53 per MWh for Danskin. The cost of off system purchases have increased from $39.9 per MWh in case IPC-E-03-13 to $58.8 per MWh in the current case. The value of off system sales has also increased, but by a lesser amount, from $20.9 per MWh in 2003 to $45.6 per MWh. It should be emphasized the current case values are based on projections by the Company.

Q. **YOU HAVE DEMONSTRATED THE INCREASES IN ENERGY COSTS OVER THE PAST 5 YEARS FOR IDAHO POWER. IS THIS A CAUSE OF HIGH LOAD FACTOR CUSTOMERS BEING ASSIGNED THE MAJOR SHARE OF THE PROPOSED RATE INCREASE?**

A. Yes. The paradoxical aspect of this increase in energy costs relative to capacity costs is the fact that Idaho Power has changed from a energy constrained utility to a capacity constrained utility over the past 15 years. This shift has been driven primarily by the growth in the residential and small commercial classes over the past dozen years. This is the reason the Company has constructed 260 MWs of gas peaking units as its latest resources. These higher energy costs are reflected in the Company's cost of service studies which pass on higher energy costs to high load factor customers. However for a utility that is capacity constrained, higher price signals should be sent to those customer classes that have the lowest load factors. The results of Idaho Power's cost of service studies does just the opposite by charging a disproportional share to customers that have high load factors.

Q. **AS YOU POINTED OUT ABOVE, THE RESIDENTIAL CLASS, (AND TO A LESSER EXTENT THE SMALL COMMERCIAL CUSTOMER CLASS) IS RECEIVING THE LOWEST PERCENTAGE INCREASE, WHILE THE HIGH LOAD FACTOR CUSTOMERS ARE RECEIVING THE HIGHEST. WHAT DOES THIS SAY ABOUT PRICE SIGNALS TO CUSTOMERS?**

A. It sends the wrong price signals, because the result of the Company's COS allocates more costs to energy than to capacity, which is reflected in the Company's proposed rates. The recommended rate increase for Schedule 19 and Special Contract customers is 2.4 times higher than for the residential class. Yet the Company has been adding peaking resources to meet the increasing demand during peak periods that is being driven largely by residential customer growth.

Q. **HAVE YOU FOUND ANOTHER CAUSE WITHIN THE COMPANY'S COST OF SERVICE STUDIES THAT HAVE SHIFTED COSTS FROM RESIDENTIAL AND SMALL COMMERCIAL CUSTOMERS TO HIGH LOAD FACTOR CUSTOMERS?**

A. Yes. As outlined in Company witness Tatum's testimony one of the changes to come out of the three cost-of-service workshops was a method of "normalizing" class coincident peak demands.

> The surrogate demand normalization methodology uses the five-year median demand ratios from the load research sample applied to the normalized monthly energy values for each customer class to determine the coincident peak demands by class. This methodology reduces the effect of any atypical demand ratios that might exist in a given test year due to unusual weather conditions. [Tatum, p. 11.]

The Company calculates system coincident demand factors for each customer class for each month. These coincident demand factors are derived by finding the kW demand at the system peak hour divided by the average kW demand for the month. These are calculated for each of the years 2003 through 2007, then the median value over the 5 year period is selected for each month for each customer class. One would expect the pattern of median values for the customer classes to be somewhat similar given typical or atypical years.

Q. **DID YOU FIND SIMILAR PATTERNS AMONG CUSTOMER CLASSES WHEN YOU EXAMINED THE PATTERN OF THE SYSTEM COINCIDENT DEMAND FACTORS?**

A. No. For the residential class six of the median values for these factors occur in 2003 with another four being found in 2004. On the other hand, for Schedule 19, eight of the median system coincident factors occur in 2006 with another two in 2007. Other customer classes show varying patterns over the five year period of median system coincident demand factors. This anomaly produces the effect that for some classes the cost of service values are being determined weighted for load patterns that occurred four or five years ago while for other classes this weighting effect occurs in more recent years.

Q. **DID YOU EXAMINE HOW THE PATTERN YOU JUST DESCRIBED ABOVE COULD IMPACT COST OF SERVICE VALUES AMONG CUSTOMER CLASSES?**

Yes. Rather than using the median values for the system coincident demand factors I substituted in the 2007 values and ran the 3 CP/12 CP model with no other changes. Use of 2007 system coincident demand factors, rather than the five year median values, produced some significant shifts among some customer classes. In general there was a shift of costs away from the higher load factor customer classes to the lower load factor classes. The residential class revenue deficiency increased nearly $5 million meaning the percent increase in rates went from 3.71% to 6.26%. [see Exhibit 205] While the Large General Service class percent increase in rates dropped to 2.12% from 9.16%, and Schedule 19's increase was reduced from 15.87% to 14.97%. These results appear to assign cost responsibility more in line with what one would expect given the growth in Idaho Power's system over the last 15 years. These results should be viewed as preliminary. The Company's Cost of Service method requires several steps of transferring large amounts of data to make this change. We are working with the Company to verify these steps have been made correctly. To the extent the results presented here vary from the Company's, we will adopt the Company's verification of these results and file revised exhibits.

Q. BY RECOMMENDING THE USE OF THE 2007 VALUES FOR SYSTEM COINCIDENT DEMAND FACTORS RATHER THAN THE MEDIAN ARE YOU SAYING COINCIDENT KW SHOULD NOT BE NORMALIZED IN SOME MANNER TO ACCOUNT FOR ATYPICAL YEARS?

A. No. I think the Company and the cost of service workshop participants were addressing this as a potential problem. However the experience of using the median method as described above has lead to anomalous results. For this case, the use of 2007 yields results that are more consistent with what one would expect given the Company's load patterns. I would recommend the Company and the parties work together to find a method of normalizing kW coincident demand factors.

Q. DO YOU HAVE OTHER RECOMMENDATIONS THAT WOULD HELP REMEDY THE PARADOXICAL RESULTS OF THE COMPANY'S COST OF SERVICE STUDIES?

I have two additional recommended changes to the cost of service method used by the Company. The cost of service results described below are based on changes from the Company's recommended 3 CP/12 CP Case. The other two changes are:

1) I recommend that the weightings for customer classes be set at full marginal cost rather than the average of marginal and imbedded weightings used by the Company. This will more accurately reflect the costs that are being incurred by the Company because marginal costs best represent the costs of additional capacity and energy from needed additional resources. See my Exhibit 206.

2) I also recommend that the Company's hydro resources be allocated between demand/energy to 75% capacity and 25% energy rather than the system average split that is currently used by Idaho Power. This is more in line with standard cost allocations and are the same values used by Rocky Mountain Power in both its current and last rate case before the Commission. See my Exhibit 207.

The results of these three modifications to the Company's approach are detailed in Exhibits 205, 206 and 207. I will outline each change separately below, and then summarize them in combination with one another.

Q. DR. READING PLEASE TURN TO YOUR FIRST MODIFICATION OF THE COST OF SERVICE STUDY PRESENTED BY THE COMPANY. WHY DO YOU BELIEVE FULL MARGINAL COST WEIGHTING REFLECTS THE COMPANY'S COSTS BETTER THAN ACTUAL VALUES?

A. As explained above, one of the problems with the class cost allocations that result from the Company's cost of service studies is that cost allocations are not reflected in the rates for those customer classes that drive costs on Idaho Power's system. Exhibits 202 and 203 depict the marginal costs of capacity and energy indicate the dramatic differences in cost over the different months of the year. Full marginal cost weightings then will reflect more fully these difference among customer classes and thus better reflect the costs each custom class is placing on the system.

Q. WHAT ARE THE RESULTS OF THIS MODIFICATION TO THE COMPANY'S 3 CP/ 12 CP MODEL?

A. It should be noted before I discuss the results of these cost of service modifications, that all the values are based on the Company receiving its full proposed increase of 9.89%. A different overall rate increase will change the percentage change for each customer class in ratio with that overall rate change.

As shown in Exhibit 206, weighting customer classes at full marginal cost, in general, lowers the percent increase on high load factor customers (Large General Service, Schedule 19, special contracts). Cost allocations to the residential and irrigation classes are increased slightly. The other classes remain about the same. This result tends to move the cost of service away from high load factor customers but it does not send a price signal to the residential class which is a major cause of the Company's increasing need for capacity.

Q. COULD YOU PLEASE EXPLAIN THE THIRD MODIFICATION YOU ARE RECOMMENDING BE MADE TO THE COST OF SERVICE STUDY PRESENTED BY THE COMPANY?

A. On page 5 of his direct testimony Company witness Tatum states,

> Demand related costs are investments in generation, transmission, and a portion of the distribution plant and the associated operation and maintenance expenses necessary to accommodate the maximum demand imposed on the Company's system. Energy related costs are generally the variable costs associated with the operation of the generating plants, such as fuel. However, due to the hydro production capability of the Company, a portion of the hydro and thermal generating plant investment has historically been classified as energy-related. [Tatum, Di. p. 5]

He goes on to say,

> Q. What did you use as your primary guide in classifying costs as either customer-, demand-, or energy related?
>
> A. I used the Electric Utility Cost Allocation Manual published by the National Association of Regulatory Utility Commissioners as my primary guide to the classification of customer-, demand-, and energy-related costs. [page 6.]

According to the NARUC Cost Allocation Manual, hydro facilities are usually treated as capacity. Mr. Tatum is correct that 'traditionally' the Company has treated, and the Commission has accepted, the allocation of the Company's hydro resources to energy. When the Company was energy constrained, rather than capacity constrained, this made sense. However now that Idaho Power is capacity constrained rather than energy constrained, and it is adding additional resources which reduces its reliance on hydro resources, it now makes sense to allocate its hydro resources more to capacity rather than energy.

Q. WHAT IS YOUR RECOMMENDATION FOR THE ASSIGNMENT OF HYDRO RESOURCES BETWEEN ENERGY AND CAPACITY?

A. A reasonable method of allocating Idaho Power's hydro resources between capacity and energy is to assign 75% capacity and 25% energy. This is the allocation used by PacifiCorp in its cost of service study in its last and current rate cases, "Production and transmission plant and non-fuel related expenses are classified as 75 percent demand related and 25 percent energy related" [PAC-E-07-05, Rocky Mountain Power, Mark E. Tucker, Di-4]. It is my understanding this capacity/energy split was established by the various states served by PacifiCorp.

There are a variety of ways hydro facilities can be allocated. These would range from 100% demand related to some mixture between demand and energy. I believe the allocation of 75% to capacity and 25% to energy is reasonable for hydro plants. The NARUC Cost Allocation Manual states, "Most hydro capacity today is being used for peaking purposes, and its costs therefore are properly classified as demand-related." [Electric Utility Cost Allocation Manual, NARUC, 1967, footnote page 33.] While the Company has numerous run-of-river facilities the major hydro complex is Hells Canyon that Idaho Power uses for peaking.

Q. WHAT IS THE RESULT OF YOUR RECOMMENDATION FOR THE ASSIGNMENT OF HYDRO RESOURCES BEING 75% CAPACITY AND 25% ENERGY?

A. Exhibit 207 displays the results of allocating the Company's hydro resources 75% to capacity and 25% to energy. This modification produces approximately the same result as reclassifying PURPA projects at the system average between capacity and energy. With this change, the revenue requirement for high load factor customers is lowered with the residential class being assigned a slightly higher increase. In addition, as was true with the other two recommended changes, irrigation customers receive a higher percent increase.

Q. YOU HAVE INDICATED WHAT THE RESULTS ARE FOR EACH OF YOUR THREE RECOMMENDED CHANGES INDEPENDENTLY. WHAT IS THE IMPACT IF ALL THREE ARE IMPLEMENTED?

A. These results are shown in Exhibit 208. When the three modifications are made simultaneously the high load factor customers revenue deficiency are lowered significantly and the percentage increase for irrigation customers increases slightly from 28.54% to 29.09%. The residential class's revenue deficiency increases by $9.3 million for a rate increase of 8.52%.

Q. YOU HAVE DESCRIBED THREE CHANGES TO THE COMPANY'S COST OF SERVICE METHOD. ARE YOU ADVOCATING THESE CHANGES BE IMPLEMENTED BY THE COMMISSION?

A. Yes. The modifications I have recommended align cost responsibility more in line with the Company's changing load growth patterns. These changes will also better provide price signals to the customer classes that are creating costs through system load growth. The results of these changes also increase the revenue requirement for the irrigation class only slightly. The irrigation class has the misfortune of having the need for power during summer on peak that is when the Company's system needs are growing the fastest. Irrigation load is not growing. Yet due to increasing residential and commercial demand, their cost allocations are increasing due to their relatively high summer use.

Reading Test Year Testimony

Q. Dr. Reading, have you read the testimony and reviewed the exhibits of Company witness Lori Smith?

A. Yes. Ms. Smith used the Company's actual financial results for calendar 2007 as a foundation to project the calendar 2008 test year used by Idaho Power for its proposed rates in this case. She develops the 2008 forecasted test year by adjusting 2007 values for operating expenses and rate base. Three and five year compound growth rates are used to forecast investments of the Company that are less than $2 million. In addition certain items are annualized as if they were in existence the full test year.

Q. Why is the Company using a fully forecasted test year in this case?

A. According to Ms. Smith,

> In order to meet the legal requirement that rates be fair, just, reasonable, and sufficient, the Commission must establish a test year that most closely reflects the investment and expense levels that will exist at the time new rates are implemented. At this time, the Company believes that a 2008 test year best satisfies that requirement. [Smith Direct, pgs 18,19.]

It is understandable why the Company wants rates that most closely match their costs and revenues during the period in which those rates will be in effect.

Q. Are you saying you support the utility basing rates on a forecasted test year?

A. No. As I stated in my filed testimony in the Company's last rate case [IPC-E-07-08] that I was, and remain, opposed to the forecasted test year for both theoretical and practical reasons:

> One of the pillars of ratemaking is that ratepayers should only shoulder the burden of 'known and measurable' costs. Projections, by definition, are a presumption about future events. The standard approach for a forecasted test year, and the one used by the Company, is to make projections base on historical data and the adjusted for expected changes. [Reading Direct Testimony, IPC-E-07-07, p. 5.]

In reality the assumptions and projections made by the Company may or may not in fact come true, yet ratepayers will be paying as if the projections were true.

Q. You said you also have practical reasons for opposing a forecasted test year, could you briefly outline those concerns?

A. Yes, in my direct testimony in case IPC-E-07-08 I quoted the well-known regulatory expert James Bonbright:

> In the first place, the commission's staff must audit the utility's books. For ratemaking purposes, only just and reasonable expenses are allowed; only used and useful property is permitted in the rate base. In the second place, the commission must have a basis for estimating future revenue requirements. This estimate is one of the most difficult problems in a rate case. A commission is setting rates for the future but it has only past experience (expenses, revenues, demand conditions) to use as a guide. [James Bonbright, with Albert Danielsen and David Kamerschen, Principles of Public Utility Rates, 2nd Ed., March, 1988.]

I want to complement the Company for its efforts and communication with the Staff and Interveners in the development of the forecasted test year in this case. The Company met with Staff and Interveners in a workshop and outlined their approach. The Company has worked hard to simplify the projection process and explain the foundation and methodologies used to determine the values in the 2008 test year.

Q. Are you saying you support the Company's projected 2008 test year as filed?

A. No, but due the timing of this case I am recommending a procedure that can accomplish some of the goals of the Company and alleviate some of the problems with a forecasted test year outlined above.

Q. Could you please discuss how you formed your recommendation for dealing with the forecasted test year in this docket?

A. This case was filed on June 27, 2008 with the technical hearing set for the end of December 2008. The proposed rate suspension period will end January 27, 2009 with the Commission able to suspend for an additional 60 days for good cause. I, of course, do not know what the Commission will do. However given the timing of the technical hearing the Commission will need some time to decide the case. Therefore it is reasonable to assume the final order would be issued sometime in mid-January.

We ask for, and received, in discovery from the Company [Idaho Power Company's Supplemental Response to the First Production Request of the Industrial Customers of Idaho Power, Supplemental Response for Production No. 7.] on August 15, 2008 actual financial data for the Company through June 2008 for items they projected using the 3 and 5 year compound growth rates.

Q. Did you compare the actual first six months data for 2008 with the Company's forecast?

A. Yes. I used the simplifying assumption of multiplying the six month year-to-date actual values by two and then compared that value to the Company's full projected test year. Exhibit 209 shows the results of that comparison. As can be seen, some of the estimates appear to be very close while others vary significantly. There can be all kinds of reasons why the first six months' expenditures and revenues would not exactly match the last half of the year. However, the Exhibit does demonstrate how dramatically projections and actual values can vary.

Q. You testified earlier that you have a recommendation that can resolve some of the concerns of the Company as well as the problems you identified with using a projected test year. What is your recommendation?

A. The Company should file with its rebuttal testimony, which is due on December 3rd, actual results for the first three quarters of 2008. These updated actual results should be used to compare to the projected test year calendar 2008. This would give a better indication of how the Company's projections are squaring with reality. For those items for which there is a significant difference, the Company could either make adjustments and/or explain why those discrepancies occurred. Depending on when the Commission issues its final Order, another update could be made with actual data from those additional month(s) that become available. This approach would mean rates would be set using financial data that is closer to actual rather than a full 12 month projection.

Q. DR. READING HAVE YOU REVIEWED THE TESTIMONY OF MS. MILLER REGARDING INCLUDING THE ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION ("AFUDC") COMPONENT OF CONSTRUCTION WORK IN PROGRESS ("CWIP") FOR THE HELLS CANYON RELICENSING PROJECT TO BE INCLUDED IN BASE RATES?

A. Yes, I have. I do not believe it is appropriate to include such costs in rates in this case.

Q. WHAT ARE THE PROBLEMS WITH INCLUDING THE AFUDC COMPONENT OF CWIP ASSOCIATED WITH THE HELLS CANYON RELICENSING PROJECT IN BASE RATES?

A. This Commission has a long standing precedent to disallow CWIP from rates. Here the Company is asking that the AFUDC component of CWIP be included in base rates. That is short of asking for all of the CWIP associated with this project to be included in base rates, but it is still asking for CWIP to be included in base rates.

Q. WHAT ARE THE PROBLEMS WITH INCLUDING CWIP IN BASE RATES?

A. Actually the Commission's own orders outline the reasons for disallowing CWIP from rates. In order No. 14348 issued in Case No. 1009-96 the Commission made the following declaration:

> allowing a company to earn a return on construction work in progress destroys the incentive to finish that speedily, puts on the ratepayers a risk which is properly borne by stockholders, and creates a mismatch between those who presently pay and those who, in the future, will benefit from the electric plant when it becomes used and useful. The Commission has made clear its position on this issue in recent orders [citations omitted]. We are steadfastly opposed to the inclusion of CWIP in rate base. We find that the alternative method of providing an allowance for funds used during construction (AFUDC) is just and reasonable and does not deprive the Company of anything to which it is entitled. Nothing would be served by further discussion of this matter. [at page 6]

The Commission's rational is as valid today as it was back in 1978.

Q. **THE COMPANY'S REQUEST IS RELATIVELY MODEST IN LIGHT OF THE ENTIRETY OF THE HELLS CANYON RELICENSING COSTS. WHY THE STRONG OPPOSITION?**

A. Because this is just the tip of the iceberg, if you will. Company policy witness Gale testified that the Company is embarking on a plan of construction projects that is only comparable to the time it built the Hells Canyon Complex. He noted that the Company is planning on spending almost one billion dollars in the near term on construction projects without including the Gateway West Transmission Project or the Hemingway-Boardman line. [Gale Di at page 19.]

Q. **WOULD NOT SUCH A LARGE CONSTRUCTION PLAN SUGGEST THAT THE COMPANY WILL NEED TO PUT CWIP IN RATES?**

A. Yes and no. Certainly the Company will raise the argument that putting CWIP in rates reduces future rate increases, generates internal cash flow and reduces the cost of electric plant when it does become used and useful. However, the Company's planned future developments are not certain to come on line and are also not certain to come on line when planned. The risk of failure to develop and the risk of delay is placed entirely on the ratepayer side of the ledger when a utility is allowed to place CWIP in rates. Idaho has had ambitious construction plans in the past that have not come on line and the ratepayers were protected from paying the costs of those dry hole prospects.

Q. **DO YOU HAVE ANY SPECIFIC PROJECTS IN MIND THAT WERE PLANNED BUT NOT CONSTRUCTED?**

A. Certainly. In the early 1990s Idaho Power was actively pursing a major transmission project to construct a large transmission line from Southern Idaho to Las Vegas, Nevada. It spent millions of dollars on planning, permitting and engineering that project. It subsequently abandoned the project and only recently sold its rights to build it to a third party. Had it put those costs in rates back in the 1990s those ratepayers would have paid for a project that not only did not benefit them at the time of payment, but did not benefit Idaho Power's ratepayers at all. That illustrates my concern here. Placing CWIP in rates is simply too speculative of a risk to put on the ratepayers.

Q. IDAHO POWER'S FUTURE CONSTRUCTION PLANS CALL FOR INCREASING ITS RATEBASE BY A SUBSTANTIAL AMOUNT, WOULD NOT ALLOWING CWIP IN RATES ALLOW IT TO PROCEED WITH LESS COST?

A. The unprecedented level of construction spending Idaho Power is planning may call for an unprecedented response. However, simply slipping the precedent of allowing CWIP in rates in this case is not the way to go about fashioning that response.

Q. PLEASE EXPLAIN.

A. If all of Idaho Power's planned projects come to fruition, we could easily see a doubling of its rate base and unprecedented rate increases for the ratepayers. I understand that Idaho Power may need some assistance from the Commission and the ratepayers in terms of assurance of recovery of its prudently incurred costs and we would be willing to sit down with them to fashion a response short of a blanket granting of CWIP. I don't have any specific suggestions at this time, but would be open to a compromise down the road as these possible construction projects become more real.

Q. WHAT DO YOU MEAN 'MORE REAL'?

A. As the U.S. and, indeed, the global economies currently appear to be hurtling toward a major recession, ambitious construction projects that require large quantities of debt may be mothballed for reasons other than lack of CWIP in rates. There is a possibility of major loss of load due to the weak economy that would make proceeding with some projects less than prudent. As of the time that I am writing this testimony the economy is in one of the most uncertain states I have ever seen it. I don't think now is the time to hard wire CWIP to rates until we have more clarity on each specific project and the costs associated with each specific project.

Q. WHAT IS THE STATUS OF THE VIRTUAL PEAKING RESOURCE YOU ADDRESSED IN IDAHO POWER'S LAST RATE CASE?

A. I understand that Idaho Power has contacted some entities with emergency back up generators to determine interest in their running in parallel with the Company's system. The Company has also done some very preliminary studies of the costs associated with such a program. I believe they have taken these steps in response to this Commission's urging – although in discussions with Company officials they report that Idaho Power has looked at this sort of a peak shaving program at least ten years ago.

Q. WHAT HAS THE COMPANY LEARNED FROM ITS STUDIES AND DISCUSSIONS?

A. I believe the Company learned what it set out to learn.

Q. PLEASE EXPLAIN

A. The Company has been, to say the least, less than enthusiastic about implementing a shared interest in customer owned generation for purposes of meeting peak or providing stand-by reserves. Why, I do not know. We can speculate as to the reason for its lukewarm response to the possibility of creating a virtual peaking unit at its load center, but that would not be productive at this juncture. I believe the Company's lack of enthusiasm for the program was a large driver in its conclusions that energy from such a program would be much more expensive than building new gas fired peaking units. It did conclude, however, that capacity would be much less expensive.

Q. IS THE FACT THAT ENERGY FROM A VIRTUAL PEAKING PROGRAM IS MORE EXPENSIVE THAN FROM A TRADITIONAL GAS PEAKER A FATAL FLAW?

A. Apparently from the Company's viewpoint it is. Although, with its casual approach to this program, we can conclude that creativity was not encouraged within the Company's team that was looking into the possibility of a virtual peaking program.

Q. PLEASE EXPLAIN.

A. The reason energy from customer owned back up generation is so much more expensive than energy from the company's own gas fire peakers, is because the Company assumed diesel fuel would be used in the customer owned units. The Company failed to explore ways to work with new customers prior to installation of back up generation to have those generators connect to the gas line rather than building diesel generators. If that were done, the cost of energy for the back up generators would equal the cost of energy for the Company owned generators, while the cost of capacity would be a fraction of the cost of capacity from the Company's plants. Also using gas eliminates most environmental concerns and dramatically reduces the additional expense of the interconnection.

Q. SO ARE YOU SUGGESTING THE COMPANY BE DIRECTED TO IMPLEMENT A VIRTUAL PEAKING PLANT PROGRAM FOR NEW INSTALLATIONS?

A. Yes. On a going forward basis the Company should be directed to exercise its best efforts to work with its customers who are installing new customer-owned back up generation to enlist them in the virtual peaking program. If the Company, which had looked at this type of a program at least ten years ago, had implemented it then, I am sure it would now have a valuable addition to its arsenal for meeting that very expensive summer peak.

Q. ARE THERE OTHER UTILITIES THAT HAVE IMPLEMENTED PROGRAMS THAT GRADUALLY REDUCE THEIR SYSTEM PEAK?

A. Interestingly, and unexpectedly, one only need to look at United Water to find an example of a reluctant utility that was required to implement a successful peak shaving program. This Commission initiated the concept of requiring United Water (then Boise Water) to encourage the installation of dual irrigation systems in those new subdivisions where irrigation surface water was available. The tool the Commission used was a punitive hook-up fee for customers who did not comply. Although the regulatory tool ran afoul of the prohibition against discriminatory rates – Boise City picked up the ball and made such a program mandatory through its zoning regulations. As a result of this Commission's initiative, United Water's summer peak is much less now than it would have been without dual irrigation systems being installed as a matter of course.

Q. **WHAT IS THE LESSON TO BE LEARNED FROM THE BOISE WATER EXPERIENCE?**

A. Utilities have an incentive to build and own their own resources. Programs that reduce their ability to build new plant (gas fired peakers or surface water treatment plants) reduce their ability to add to stockholder value. However, that also creates a tension between the customer goal of having rates as low as possible. Here I believe Idaho Power has been caught up at the intersection of those two competing interests. The lesson to be learned is that the virtual peaking program can clearly be part of the solution, but only if this Commission wants it to be, because Idaho Power is obviously not going to take the initiative.

Q. DOES THIS END YOUR TESTIMONY AS OF OCTOBER 24, 2008?

A. Yes.

CERTIFICATE OF SERVICE

I hereby certify that on the 24th day of October, 2008, I served the foregoing DIRECT TESTIMONY OF DR. DON READING in Case NO. IPC-E-08-10 to the following as indicated below:

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Nina M. Curtis

Don C. Reading

Present position	Vice President and Consulting Economist
Education	B.S., Economics C Utah State University M.S., Economics C University of Oregon Ph.D., Economics C Utah State University
Honors and awards	Omicron Delta Epsilon, NSF Fellowship
Professional and business history	Ben Johnson Associates, Inc.: 1989 ---- Vice President 1986 ---- Consulting Economist Idaho Public Utilities Commission: 1981-86 Economist/Director of Policy and Administration Teaching: 1980-81 Associate Professor, University of Hawaii-Hilo 1970-80 Associate and Assistant Professor, Idaho State University 1968-70 Assistant Professor, Middle Tennessee State University
Firm experience	Dr. Reading provides expert testimony concerning economic and regulatory issues. He has testified on more than 35 occasions before utility regulatory commissions in Alaska, California, Colorado, the District of Columbia, Hawaii, Idaho, Nevada, North Dakota, Texas, Utah, Wyoming, and Washington. Dr. Reading has more than 30 years experience in the field of economics. He has participated in the development of indices reflecting economic trends, GNP growth rates, foreign exchange markets, the money supply, stock market levels, and inflation. He has analyzed such public policy issues as the minimum wage, federal spending and taxation, and import/export balances. Dr. Reading is one of four economists providing yearly forecasts of statewide personal income to the State of Idaho for purposes of establishing state personal income tax rates. In the field of telecommunications, Dr. Reading has provided expert testimony on the issues of marginal cost, price elasticity, and measured service. Dr. Reading prepared a state-specific study of the price elasticity of demand for local telephone service in Idaho and recently conducted research for, and directed the preparation of, a report to the Idaho legislature regarding the status of telecommunications competition in that state.

Exhibit 201
Reading, Di
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Dr. Reading's areas of expertise in the field of electric power include demand forecasting, long-range planning, price elasticity, marginal and average cost pricing, production-simulation modeling, and econometric modeling. Among his recent cases was an electric rate design analysis for the Industrial Customers of Idaho Power. Dr. Reading is currently a consultant to the Idaho Legislature=s Committee on Electric Restructuring.

Since 1999 Dr. Reading has been affiliated with the Climate Impact Group (CIG) at the University of Washington. His work with the CIG has involved an analysis of the impact of Global Warming on the hydo facilities on the Snake River. It also includes an investigation into water markets in the Northwest and Florida. In addition he has analyzed the economics of snowmaking for ski area's impacted by Global Warming.

Among Dr. Reading's recent projects are a FERC hydropower relicensing study (for the Skokomish Indian Tribe) and an analysis of Northern States Power's North Dakota rate design proposals affecting large industrial customers (for J.R. Simplot Company). Dr. Reading has also performed analysis for the Idaho Governor's Office of the impact on the Northwest Power Grid of various plans to increase salmon runs in the Columbia River Basin.

Dr. Reading has prepared econometric forecasts for the Southeast Idaho Council of Governments and the Revenue Projection Committee of the Idaho State Legislature. He has also been a member of several Northwest Power Planning Council Statistical Advisory Committees and was vice chairman of the Governor's Economic Research Council in Idaho

While at Idaho State University, Dr. Reading performed demographic studies using a cohort/survival model and several economic impact studies using input/output analysis. He has also provided expert testimony in cases concerning loss of income resulting from wrongful death, injury, or employment discrimination. He is currently a adjunct professor of economics at Boise State University (Idaho economic history, urban/regional economics and labor economic.)

Dr. Reading has recently completed a public interest water rights transfer case. He has also just completed an economic impact analysis of the 2001 salmon season in Idaho.

Publications

"Energizing Idaho", Idaho Issues Online, Boise State University, Fall 2006. www.boisestate.edu/history/issuesonline/fall2006_issues/index.html

The Economic Impact of the 2001 Salmon Season In Idaho, Idaho Fish and Wildlife Foundation, April 2003.

The Economic Impact of a Restored Salmon Fishery in Idaho, Idaho Fish and Wildlife Foundation, April, 1999.

The Economic Impact of Steelhead Fishing and the Return of Salmon Fishing in Idaho, Idaho Fish and Wildlife Foundation, September, 1997.

ACost Savings from Nuclear Resources Reform: An Econometric Model@ (with E. Ray Canterbery and Ben Johnson) *Southern Economic Journal*, Spring 1996.

A Visitor Analysis for a Birds of Prey Public Attraction, Peregrine Fund, Inc., November, 1988.

Investigation of a Capitalization Rate for Idaho Hydroelectric Projects, Idaho State Tax Commission, June, 1988.

"Post-PURPA Views," In Proceedings of the NARUC Biennial Regulatory Conference, 1983.

An Input-Output Analysis of the Impact from Proposed Mining in the Challis Area (with R. Davies). Public Policy Research Center, Idaho State University, February 1980.

Phosphate and Southeast: A Socio Economic Analysis (with J. Eyre, et al). Government Research Institute of Idaho State University and the Southeast Idaho Council of Governments, August 1975.

Estimating General Fund Revenues of the State of Idaho (with S. Ghazanfar and D. Holley). Center for Business and Economic Research, Boise State University, June 1975.

"A Note on the Distribution of Federal Expenditures: An Interstate Comparison, 1933-1939 and 1961-1965." In *The American Economist*, Vol. XVIII, No. 2 (Fall 1974), pp. 125-128.

"New Deal Activity and the States, 1933-1939." In *Journal of Economic History*, Vol. XXXIII, December 1973, pp. 792-810.

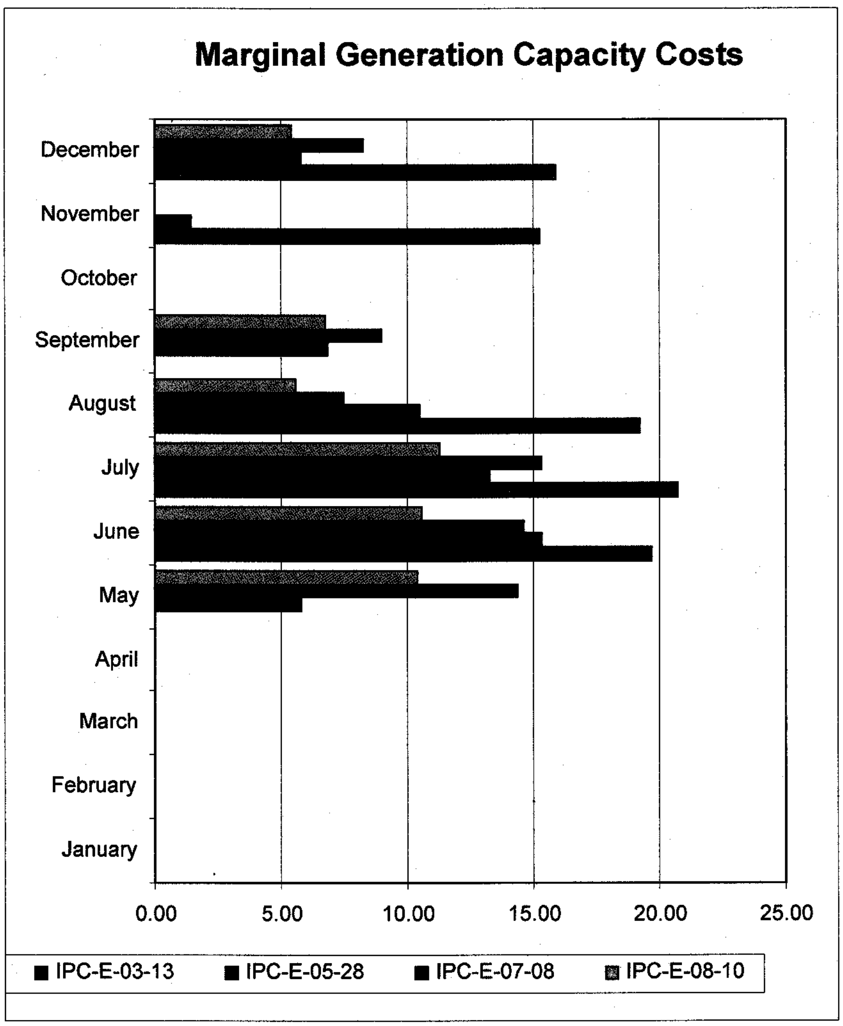

Exhibit 202
Reading, Di
IPC-E-08-10

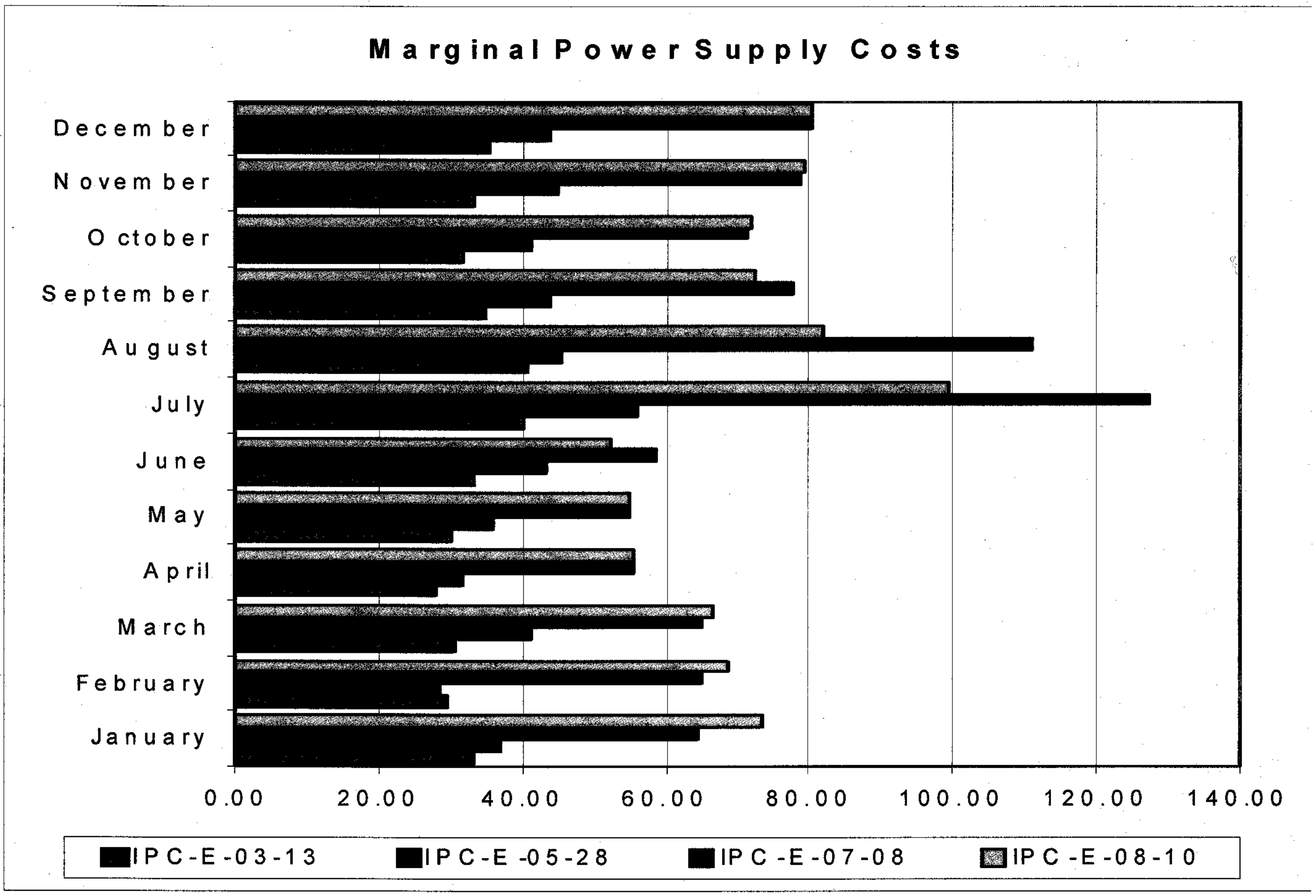

Exhibit 203
Reading, Di
IPC-E-08-10

POWER SUPPLY EXPENSES NORMALIZED INCLUDING KNOWN AND MEASURABLE POWER SUPPLY ADJUSTMENTS
RATE CASES IPC-E-03-13, IPC-E-05-28, IPC-E-07-08, AND IPC-E-08-10

	2003 test year Annual	2003 Prices mills/kwh	2005 test year Annual	2005 Prices mills/kwh	2007 After PURPA & Horizon Annual	2007 Prices mills/kwh	2008 test year Annual	2008 Prices mills/kwh
Hydroelectric Generation (mwh)	8,837,022.5		8,684,384.8		8,748,179.7		8,748,562.70	
Bridger								
Energy (mwh)	5,013,126.0		4,993,537.9		5,052,875.3		5,091,955.3	
Cost ($ x 1000)	$63,904.9	12.75	$62,513.8	12.52	$73,318.8	14.51	$82,101.9	16.12
Boardman								
Energy (mwh)	395,935.6		432,209.8		422,213.2		420,256.6	
Cost ($ x 1000)	$5,244.7	13.25	$5,455.3	12.62	$5,874.6	13.91	$6,035.7	14.36
Valmy								
Energy (mwh)	1,768,646.1		1,823,242.6		1,826,704.5		1,877,246.2	
Cost ($ x 1000)	$25,999.8	14.70	$30,110.2	16.51	$40,291.4	22.06	$45,280.4	24.12
Danskin								
Energy (mwh)	804.6		4,052.4		2,970.9		32,258.7	
Cost ($ x 1000)	$38.1		$250.8		$292.1		$2,577.4	
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$3,218.4		$2,861.1		$2,826.5		$3,730.3	
Total Cost	$3,256.5	4,047.38	$3,111.9	767.92	$3,118.6	1,049.72	$6,307.6	195.53
Bennett Mountain								
Energy (mwh)			35,113.5		45,890.0		9,506.5	
Cost ($ x 1000)			$1,832.0		$3,967.3		$779.2	
Fixed Capacity Charge - Gas Transportation ($ x 1000)								
Total Cost			$1,832.0	52.17	$3,967.3	86.45	$779.2	81.96
Purchase Power (Excluding CSPP)								
Market Energy (mwh)	210,815.2		367,321.8		401,368.2		471,979.9	
Contract Energy (mwh)	99,360.0		99,360.0		406,843.9		517,249.5	
Total Energy Excl. CSPP (mwh)	310,175.2		466,681.8		808,212.1		989,229.3	
Market Cost ($ x 1000)	$7,976.9	37.84	$21,308.0	58.01	$37,984.5	94.64	$32,444.3	68.74
Contract Cost ($ x 1000)	$4,400.0	44.28	$4,421.5	44.50	$19,299.4	47.44	$25,682.5	49.65
Total Cost Excl. CSPP ($ x 1000)	$12,376.9	39.90	$25,729.5	55.13	$57,283.9	70.88	$58,126.7	58.76
Purchase mills per kWh Total	***39.9***		***55.1***		***70.9***		***58.8***	
Surplus Sales								
Energy (mwh)	3,024,695.8		2,572,405.5		2,950,604.2		2,419,052.0	
Revenue Including Transmission Costs ($ x 1000)	$66,119.4	21.86	$79,349.7	30.85	$145,834.2	49.43	$112,629.5	46.56
Transmission Costs ($ x 1000)	$3,024.7	1.00	$2,572.4	1.00	$2,950.6	1.00	$2,419.1	1.00
Revenue Excluding Transmission Costs ($ x 1000)	$63,094.8	20.86	$76,777.3	29.85	$142,883.6	48.43	$110,210.4	45.56
Sales mills per kWh include Trans	***20.9***		***29.8***		***48.4***		***45.6***	
Net Purchase-Sales	***$50,717.8***		***$51,047.8***		***$85,599.7***		***$52,083.7***	
Net Power Supply Costs ($ x 1000)	$47,688.1		$51,975.2		$40,971.0		$88,421.1	

Exhibit 204
Reading, Di
IPC-E-08-10

3CP/12CP AS FILED BY IDAHO POWER

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
				GEN SRV	GEN SRV	AREA	LG POWER	IRRIGATION	UNMETERED	MUNICIPAL	TRAFFIC	SC	SC	SC
	TOTAL	RESIDENTIAL	GEN SRV	PRIMARY	SECONDARY	LIGHTING	PRIMARY	SECONDARY	GEN SERVICE	ST LIGHT	CONTROL	DOE/INL	JR SIMPLOT	MICRON
		(1)	(7)	(9-P)	(9-S)	(15)	(19-P)	(24-S)	(40)	(41)	(42)			
REVENUE DEFICIENCY	66,588,287	11,786,451	1,199,965	737,390	13,002,374	(420,382)	11,153,424	21,987,506	(24,881)	(676,657)	68,601	1,478,552	1,412,135	4,883,809
PERCENT CHANGE REQUIRED	9.89%	3.71%	7.91%	4.75%	9.16%	-41.85%	15.87%	28.54%	-2.57%	-29.24%	44.20%	25.37%	28.14%	24.41%
RETURN AT CLAIMED ROR	178,985,602	80,982,556	3,686,240	4,333,308	37,407,989	76,386	19,119,779	24,860,639	234,022	286,148	45,923	1,488,777	1,545,758	4,918,079
EARNINGS DEFICIENCY	40,553,159	7,178,107	730,795	449,080	7,918,620	(256,018)	6,792,585	13,390,686	(15,153)	(412,093)	41,779	900,458	860,009	2,974,305

3CP/12CP USING 2007 CP

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
REVENUE DEFICIENCY	66,588,287	19,900,255	1,303,302	1,146,116	3,009,906	(423,314)	10,522,095	23,487,009	(3,558)	(551,830)	58,453	1,472,544	1,512,819	5,154,490
PERCENT CHANGE REQUIRED	9.89%	6.26%	8.60%	7.38%	2.12%	-42.14%	14.97%	30.48%	-0.37%	-23.84%	37.66%	25.27%	30.15%	25.77%
RETURN AT CLAIMED ROR	178,985,602	81,889,351	3,698,082	4,379,726	36,290,466	75,886	19,053,667	25,020,851	236,334	300,130	44,763	1,488,800	1,557,285	4,950,262
EARNINGS DEFICIENCY	40,553,159	12,119,522	793,728	698,000	1,833,073	(257,804)	6,408,097	14,303,903	(2,167)	(336,072)	35,599	896,799	921,327	3,139,153
CHANGE IN EARNINGS DEFICENCY		4,941,415	62,934	248,920	(6,085,547)	(1,786)	(384,488)	913,217	12,986	76,021	(6,180)	(3,659)	61,318	164,848

Exhibit 205
Reading, Di
IPC-E-08-10

3CP/12CP AS FILED BY IDAHO POWER

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
				GEN SRV	GEN SRV	AREA	LG POWER	IRRIGATION	UNMETERED	MUNICIPAL	TRAFFIC	SC	SC	SC
	TOTAL	RESIDENTIAL	GEN SRV	PRIMARY	SECONDARY	LIGHTING	PRIMARY	SECONDARY	GEN SERVICE	ST LIGHT	CONTROL	DOE/INL	JR SIMPLOT	MICRON
		(1)	(7)	(9-P)	(9-S)	(15)	(19-P)	(24-S)	(40)	(41)	(42)			
REVENUE DEFICIENCY	66,588,287	11,786,451	1,199,965	737,390	13,002,374	(420,382)	11,153,424	21,987,506	(24,881)	(676,657)	68,601	1,478,552	1,412,135	4,883,809
PERCENT CHANGE REQUIRED	9.89%	3.71%	7.91%	4.75%	9.16%	-41.85%	15.87%	28.54%	-2.57%	-29.24%	44.20%	25.37%	28.14%	24.41%
RETURN AT CLAIMED ROR	178,985,602	80,982,556	3,686,240	4,333,308	37,407,989	76,386	19,119,779	24,860,639	234,022	286,148	45,923	1,488,777	1,545,758	4,918,079
EARNINGS DEFICIENCY	40,553,159	7,178,107	730,795	449,080	7,918,620	(256,018)	6,792,585	13,390,686	(15,153)	(412,093)	41,779	900,458	860,009	2,974,305

13CP/12CP with Full MC Weighting

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
REVENUE DEFICIENCY	66,588,287	12,070,823	1,179,837	691,983	12,714,324	(406,508)	10,772,093	22,635,695	(18,355)	(674,801)	70,396	1,422,170	1,393,466	4,737,165
PERCENT CHANGE REQUIRED	9.89%	3.80%	7.78%	4.45%	8.96%	-40.47%	15.33%	29.38%	-1.90%	-29.16%	45.36%	24.40%	27.77%	23.68%
RETURN AT CLAIMED ROR	178,985,602	81,010,941	3,684,230	4,328,776	37,379,236	77,771	19,081,715	24,925,340	234,674	286,333	46,103	1,483,149	1,543,894	4,903,441
EARNINGS DEFICIENCY	40,553,159	7,351,293	718,537	421,427	7,743,194	(247,569)	6,560,349	13,785,441	(11,179)	(410,963)	42,872	866,120	848,639	2,884,997
CHANGE IN EARNINGS DEFICENCY		$173,186	($12,258)	($27,653)	($175,426)	$8,449	($232,236)	$394,755	$3,974	$1,130	$1,094	($34,337)	($11,370)	($89,309)

Exhibit 206
Reading, Di
IPC-E-08-10

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
				GEN SRV	GEN SRV	AREA	LG POWER	IRRIGATION	UNMETERED	MUNICIPAL	TRAFFIC	SC	SC	SC
	TOTAL	RESIDENTIAL	GEN SRV	PRIMARY	SECONDARY	LIGHTING	PRIMARY	SECONDARY	GEN SERVICE	ST LIGHT	CONTROL	DOE/INL	JR SIMPLOT	MICRON
		(1)	(7)	(9-P)	(9-S)	(15)	(19-P)	(24-S)	(40)	(41)	(42)			
3CP/12CP AS FILED BY IDAHO POWER														
REVENUE DEFICIENCY	66,588,287	11,786,451	1,199,965	737,390	13,002,374	(420,382)	11,153,424	21,987,506	(24,881)	(676,657)	68,601	1,478,552	1,412,135	4,883,809
PERCENT CHANGE REQUIRED	9.89%	3.71%	7.91%	4.75%	9.16%	-41.85%	15.87%	28.54%	-2.57%	-29.24%	44.20%	25.37%	28.14%	24.41%
RETURN AT CLAIMED ROR	178,985,602	80,982,556	3,686,240	4,333,308	37,407,989	76,386	19,119,779	24,860,639	234,022	286,148	45,923	1,488,777	1,545,758	4,918,079
EARNINGS DEFICIENCY	40,553,159	7,178,107	730,795	449,080	7,918,620	(256,018)	6,792,585	13,390,686	(15,153)	(412,093)	41,779	900,458	860,009	2,974,305
BASE CASE; HYDRO SET AT .25 ENERGY/.75 DEMAND														
REVENUE DEFICIENCY	66,588,287	16,378,472	1,207,550	625,825	12,380,082	(433,174)	9,719,714	20,724,160	(44,863)	(735,015)	68,997	1,358,950	1,202,702	4,134,887
PERCENT CHANGE REQUIRED	9.89%	5.15%	7.96%	4.03%	8.72%	-43.12%	13.83%	26.90%	-4.64%	-31.76%	44.46%	23.32%	23.97%	20.67%
RETURN AT CLAIMED ROR	178,985,602	81,657,536	3,687,296	4,314,295	37,300,246	74,274	18,887,391	24,732,826	230,853	276,641	45,923	1,467,650	1,511,956	4,798,716
EARNINGS DEFICIENCY	40,553,159	9,974,709	735,414	381,136	7,539,636	(263,809)	5,919,436	12,621,291	(27,322)	(447,634)	42,020	827,619	732,462	2,518,201
CHANGE IN EARNINGS DEFICENCY		$2,796,602	$4,619	($67,944)	($378,984)	($7,791)	($873,148)	($769,395)	($12,169)	($35,541)	$241	($72,839)	($127,548)	($456,104)

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
				GEN SRV	GEN SRV	AREA	LG POWER	IRRIGATION	UNMETERED	MUNICIPAL	TRAFFIC	SC	SC	SC
	TOTAL	RESIDENTIAL	GEN SRV	PRIMARY	SECONDARY	LIGHTING	PRIMARY	SECONDARY	GEN SERVICE	ST LIGHT	CONTROL	DOE/INL	JR SIMPLOT	MICRON
		(1)	(7)	(9-P)	(9-S)	(15)	(19-P)	(24-S)	(40)	(41)	(42)			
3CP/12CP AS FILED BY IDAHO POWER														
REVENUE DEFICIENCY	66,588,287	11,786,451	1,199,965	737,390	13,002,374	(420,382)	11,153,424	21,987,506	(24,881)	(676,657)	68,601	1,478,552	1,412,135	4,883,809
PERCENT CHANGE REQUIRED	9.89%	3.71%	7.91%	4.75%	9.16%	-41.85%	15.87%	28.54%	-2.57%	-29.24%	44.20%	25.37%	28.14%	24.41%
RETURN AT CLAIMED ROR	178,985,602	80,982,556	3,686,240	4,333,308	37,407,989	76,386	19,119,779	24,860,639	234,022	286,148	45,923	1,488,777	1,545,758	4,918,079
EARNINGS DEFICIENCY	40,553,159	7,178,107	730,795	449,080	7,918,620	(256,018)	6,792,585	13,390,686	(15,153)	(412,093)	41,779	900,458	860,009	2,974,305
RATES OF RETURN - INDEX	1.000	1.178	1.037	1.159	1.019	5.626	0.834	0.597	1.377	3.155	0.117	0.511	0.574	0.511
3CP/12CP with 2007 CP, Full MC Weighting, Hydro at 25% Energy/75% Demand														
REVENUE DEFICIENCY	66,588,287	27,099,041	1,355,886	1,195,541	(853,605)	(443,992)	9,064,014	22,409,493	(19,560)	(568,832)	54,521	1,378,920	1,346,761	4,570,099
PERCENT CHANGE REQUIRED	9.89%	8.52%	8.94%	7.70%	-0.60%	-44.20%	12.90%	29.09%	-2.02%	-24.58%	35.13%	23.66%	26.84%	22.85%
RETURN AT CLAIMED ROR	178,985,602	82,946,981	3,705,778	4,384,430	35,706,851	72,595	18,818,215	24,919,465	233,741	296,697	44,124	1,471,568	1,529,882	4,855,274
EARNINGS DEFICIENCY	40,553,159	16,503,679	825,753	728,101	(519,857)	(270,397)	5,520,106	13,647,682	(11,912)	(346,426)	33,204	839,781	820,196	2,783,251
RATES OF RETURN - INDEX	1.000	1.036	1.005	1.078	1.312	6.109	0.914	0.585	1.359	2.803	0.320	0.555	0.600	0.552
CHANGE IN EARNINGS DEFICENCY		$9,325,572	$94,958	$279,020	($8,438,477)	($14,379)	($1,272,479)	$256,996	$3,241	$65,667	($8,575)	($60,677)	($39,814)	($191,054)

Exhibit 208
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PROJECT TEST YEAR COMPARED TO SIX MONTHS ACTUAL

Description	Y-T-D Actuals June 2008	Projected Test Year 2008	Y-T-D Actuals times 2	Percent of Actual
REVENUES				
Total other operating revenues..	$19,383,561	$38,855,834	$38,767,122	100.2%
Other Revenues (Acct 415): Total	$419,699	$1,022,527	$839,398	121.8%
Net income (earnings to Idaho Power Company)............	($1,064,296)	$6,828,651	($2,128,593)	-320.8%
EXPENSES				
Other Expenses (Acct 416): Total	$212,566	$632,354	$425,132	148.7%
Total electric operation & mainten exp.	$151,631,416	$295,910,705	$303,262,832	97.6%
Total property insurance..	$1,532,063	$3,196,433	$3,064,126	104.3%
Total regulatory commission expenses............................	$2,239,059	$6,617,258	$4,478,118	147.8%
Amort., Adj, Gain/Loss Regulatory Assets	($22,236)	($32,881)	($44,472)	73.9%
DEFFERED PROGRAMS				
IPUC Order 27660 / 27722 / 28041.................................	$6,485,237	$4,863,935	$12,970,474	37.5%
Other Total..	$1,646,243	$1,378,360	$3,292,486	41.9%

source: Idaho Power Company's Supplemental Response to the First Production Request of the Industrial Customers of Idaho Power, Supplemental Response for Production No. 7.

Exhibit 209
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IPC-E-08-10