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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 THE STATE OF IDAHO.	)	**CASE NO. IPC-E-07-8**

REBUTTAL TESTIMONY OF KEITH HESSING

IDAHO PUBLIC UTILITIES COMMISSION

JANUARY 4, 2008

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

A. My name is Keith D. Hessing and my business address is 472 W. Washington Street, Boise, Idaho.

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

A. I am employed by the Idaho Public Utilities Commission as a Public Utilities Engineer.

Q. Are you the same Keith Hessing that previously submitted testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. I will address portions of the testimonies of Dr. Dennis Peseau, Dr. Don Reading, Dr. Dennis Goins and Mr. Anthony Yankel.

Cost of Service Matrix

Q. Have you prepared a matrix that shows differences in Cost of Service (COS) assumptions proposed by the various parties to assist in the discussion of the major COS issues in this case?

A. Yes. Staff Exhibit No. 123 consists of two pages and compares the COS methods proposed in this case and the COS method used as a revenue allocation guide by the Commission in Case No. IPC-E-03-13. The matrix compares the proposed methods in three areas: methodology, classification of costs as demand or energy related and the

composition of allocation factors.

High load factor (LF) customers proposed three main COS modifications that benefit them in this case. They are; the classification of costs as demand related rather than energy related, the elimination of the averaging of weighted and unweighted allocators in favor of weighted allocation factors, and a reduction in the number of coincident peaks used in determining allocation factors.

The lower load factor irrigation class proposed a modification that benefited them. Mr. Yankel proposed that one of the two averaged allocation factors be weighted by expected load growth over a 10-year period. Irrigation load growth has been and is expected to continue to be quite small. This weighting greatly reduces COS for the irrigation class.

Q. Please illustrate the use of the matrix.

A. To illustrate the use of the matrix I will briefly discuss the COS method used by the Commission in Case No. IPC-E-03-13. It is the first method summarized on page 1 of Staff Exhibit No. 123. It is the same general method as the Base Case method presented by the Company in this filing. Hydro and coal production plant were classified as demand and energy related based on the Idaho jurisdictional Load Factor (LF). Natural gas fired peaking plant investment was classified as 100% demand related.

Non-PURPA purchased power costs were classified as 100% energy related and PURPA purchased power costs were classified as energy related except for a small percentage. Six percent of the costs were classified as demand related based on contractual capacity payments made to a few generators. Opportunity sales revenues were classified as 100% energy related.

The D10 allocator applies to most demand related costs. It is the average of the weighted and unweighted allocator calculations. The unweighted allocation factor was based on 12 monthly coincident peaks. The weighted allocation factor was based on the five highest coincident peaks weighted by the monthly marginal cost of capacity.

The D13 allocator applies to transmission costs. It is the average of weighted and unweighted allocator calculations. The unweighted allocator was based on 12 monthly coincident peaks. The weighted allocator was based on the three highest coincident peaks weighted by the monthly marginal cost of transmission.

The E10 allocator is applied to energy related costs. It is based on the monthly weighted energy use by class in the test year. The weighting factors are the monthly marginal costs of energy. The weighted factor was not averaged with the unweighted factor in the IPC-E-03-13 case.

The matrix shows the COS methods employed by the various parties in a similar format.

Making Sense of Cost of Service Results

Q. Please address the major concerns that you have with Dr. Peseau's and Dr. Reading's testimonies.

A. Their major theme is that COS results do not make sense and, therefore, the methodology must be changed. Dr. Peseau concludes that all four of the Company's filed COS studies are methodologically flawed and that the results are counterintuitive. He then proposes very substantial changes to the Base Case COS method. I do not agree that the Base Case method should be changed. Unnecessary changes in methodology shift costs unnecessarily. Base Case study results make sense and are explainable. I offer the following hypothetical example in explanation. I have prepared a residential load growth scenario using the Company's Base Case COS model. I started with the Company's Base Case COS results, grew the residential load and tracked the changes in COS results in a three step process. The example examines changes in COS results caused by changes in: (1) power supply costs, (2) demand and energy allocators and (3) retail revenue.

Q. Please provide your assumptions.

A. I assumed the following:

1) A 250,000 MWh growth in annual residential

load. (Generation Level)

2) That power supply costs to serve the load are incurred at 62.79 $/MWh. Therefore, the cost of power supply is $15,697,500 (250,000 x 62.79).

3) That the costs were Purchased Power costs booked in Account 555.1. All Account 555.1 costs are classified as 100% energy related.

4) That Base Case residential monthly energy and demand amounts grew in proportion to normalized amounts. This allowed the calculation of new allocation factors for all classes (E10, D10, and D13).

5) That residential sales were 89.1% of the generation level growth in load due to 10.9% delivery system losses. Residential sales are 222,750 MWh (250,000 x .891).

6) That the increased retail revenue associated with residential sales occurred at 59.24 $/MWh, which is current average residential revenue per MWh. This produces increased residential revenue associated with load growth of $13,195,710 (59.24 x 222,750).

Q. Have you prepared an exhibit showing the results of your analysis?

A. Yes. Staff Exhibit No. 124 is a three page exhibit that shows COS results from the three step process I employed.

Q. Please discuss the results shown on page 1 of Staff Exhibit No. 124.

A. Page 1 shows COS results associated with adding $15,697,500 of energy related costs to Account 555.1. (Assumptions 1 through 3 above) Column G shows that the amount, $15,697,500, tracked through properly as operating expense. Column J shows that the overall increase in revenue requirement tracked through correctly because it is the operating expense grossed up, $25,775,295 (15,697,500 x 1.642). Column L shows that the high load factor customer classes (DOE, Simplot, Micron and Schedule 19) were allocated the lowest ¢/kWh increases which were also the highest percentage increases as shown in Column K. This is the phenomenon discussed in my direct testimony, that relatively small ¢/kWh increases will produce relatively large percentage increases when the initial rate is relatively small. At this step COS results reflect only an expense increase and do not yet tie that expense increase to residential load growth.

I would observe that this result is similar to a result that might be produced by increased unit costs of natural gas or coal used to fuel generators or an increase

in the unit cost of purchased power without accompanying growth in load.

Q. What does page 2 of Staff Exhibit No. 124 show?

A. Page 2 shows COS results that capture the effects of assumptions 1 through 5. Page 2 again shows the operating expense increase shown on page 1 but ties that expense to residential load growth. It does this by incorporating changes in energy and demand allocators. The allocation factors for every class, except the residential class, went down and residential class factors went up. The allocation factor changes are not shown on page 2 but their effects are. For example, when page 2 is compared to page 1, Column G still totals to $15,697,500 with all classes receiving a decreased allocation except the residential class. The allocator changes also redistributed some rate base amounts and other revenue amounts with the same pattern. The overall increase shown in Column J remains the same but the class amounts are redistributed with the residential amount being the only one that increased. It is not surprising that Column K shows the largest percentage increase to be the residential class increase. Column K also shows high LF class increases to be approximately half the residential class increase. This appears to me to be the type of results that Dr. Peseau and Dr. Reading were expecting but did not

see. The ¢/kWh amounts shown in Column L include the additional retail energy sales associated with the growth in residential load which is shown in Column D.

Q. What does page 3 of Staff Exhibit No. 124 show?

A. Page 3 shows the difference in COS results caused by incorporating all six of my residential load growth assumptions. The difference between page 2 and page 3 is that page 3 credits the residential class with the revenue created by the growth in load. Column E shows that revenue. Columns F, G and H do not change. The class revenue requirement allocations in Column J do not change except for the residential class. The residential revenue requirement increase is offset dollar for dollar with the increase in load growth revenue. The residential class goes from deserving the largest increase to deserving a decrease while all other class results remain unchanged.

Q. How do the results of the hypothetical situation that you just discussed relate to the COS results in the current rate case?

A. The analysis of the hypothetical situation explains in adequate detail the effect that residential growth and high power supply cost has on all customer classes. There is certainly more going on in the COS studies presented by the Company in this case than growth in the power supply costs of one customer class, but the

COS results in the hypothetical case go a long way in showing that the COS results filed by the Company in the current case are not counterintuitive.

Q. In your previous example the cost increase was energy related. Did you prepare a hypothetical example to demonstrate the effects of demand related cost increases on COS results?

A. Yes. I again started with the Company's Base Case method and results. I added $100,000,000 in gas fired peaking investment to Accounts 340 - 346. Accounts 340 - 346 are classified as 100% demand related. Staff Exhibit No. 125 shows the COS impact of the plant addition.

Q. Please explain Staff Exhibit No. 125.

A. The format is the same as used in the previous hypothetical example. Column H shows that the $100,000,000 rate base addition flowed through the model and also shows how the cost was allocated to the various customer classes. Column J shows that the $100,000,000 investment produced approximately $14,000,000 in increased revenue requirement. Columns L and K once again show that high load factor customers receive smaller ¢/kWh increases than residential customers but a larger percentage increase. This occurs for the same reasons here as those discussed in the previous hypothetical example.

Q. Why does it matter to high LF customers whether

costs are energy related or demand related?

A. Because a lower percentage of costs are allocated to high LF customers when costs are considered to be demand related as opposed to energy related.

Q. Please provide the conclusions you reach from the hypothetical examples you have discussed.

A. High LF customer percentage increases higher than the average are due to increased production costs relative to existing rates and the lack of significant offsetting revenue. The COS results obtained from the Base Case COS method are correctly calculated, make sense and are reasonable and should be used by the Commission as the starting point in revenue allocation to the various customer classes in this case.

Dr. Peseau's Cost of Service Study

Q. Dr. Peseau filed COS results on behalf of Micron. Please discuss his cost of service study.

A. Dr. Peseau discarded all four of the COS methodologies presented by the Company and presented his own COS method (see Staff Exhibit No. 123). His COS method is a substantial modification of the Company's Base Case method. He ended up with what I would call a weighted 3CP method. He removed the averaging of the weighted and unweighted demand and energy allocators (E10, D10, D13). He also weighted 9 months as zero in determining demand

allocators. His marginal cost weighted demand allocation factors were entirely developed using June, July and August data. These demand allocators, based entirely on data for the three summer months, were used to allocate all demand related production costs and all transmission costs, since all transmission is classified as demand related. The results are predictable. The irrigators' rates are 94% below full COS while other customer class rates are above or near full COS. His revenue allocation proposal is that the irrigation class receive twice the average increase and that the remaining increase be spread to all other customer classes on a uniform percentage basis. This means that all customer classes, except the irrigators, receive an increase below the average increase.

Q. Please discuss the effects of and the reasons for averaging weighted and unweighted allocators.

A. Averaging of weighted and unweighted allocators is a compromise. Marginal cost weighting factors are the greatest in the summer time. The application of marginal cost weighted allocation factors substantially impact the irrigation class. The application of an averaged allocator softens the impact on the irrigation class. It removes part of the revenue requirement that would otherwise be assigned to the class and spreads it over other classes. Every party that has filed COS results and a revenue spread

recommendation in this case has done something similar. They have proposed that the irrigation increase be capped and that the unrecovered amount be spread to all other classes.

Another benefit of averaging weighted and unweighted allocators is that allocations reflect a value related to each class's usage characteristics for every month. I believe that capacity and energy have value in every month. As previously discussed, Dr. Peseau's COS method weights capacity costs as zero in nine months of the year and, therefore, employs demand allocators based on only three months of class characteristics. The Base Case method recommended by Staff weights six months as zero in the development of demand related allocators but then averages those zero months with an unweighted allocator calculated using coincident peak values for every month. Thus, the averaged demand allocator reflects a value based on class characteristics for all months.

Q. Is it wrong to use allocators in COS studies that do not reflect the full impact of marginal cost weighting?

A. No. The choice to use weighted or unweighted COS allocators or something in between is a judgement call that is influenced by ones choice of policy objectives. Dr. Peseau would have us believe that unweighted 12CP demand allocators have fallen out of favor and are no longer in

use. That is not true in Idaho. Both Rocky Mountain Power and Avista use unweighted 12 CP demand allocators as the primary demand allocators in their COS studies.

Classification of Power Supply Costs

Q. Staff Exhibit No. 123 indicates that three parties in this case have proposed that one or both of the sub-accounts under Account 555 purchased power be classified as something other than 100 percent and 97% energy related. What treatment do you propose for the classification of these costs?

A. Account 555.2 contains the cost of PURPA purchases. I agree that PURPA purchases have some capacity value. I also believe that other short and long-term purchases are made to meet the capacity and energy needs of the system. These costs are contained in Account 555.1. A portion of these costs should be classified as demand related as well. I further believe that Account 447 opportunity sales revenue consists of not only revenue from self-generation in a favorably priced market but also revenue from the sale of unused power purchased in advance to hedge against a variety of conditions under the Company's Risk Management Plan. Some of this resold power was purchased for capacity reasons. Revenues from the sale of power purchased for capacity reasons should be credited back to customer classes on the same capacity basis that

was used to classify the initial purchase cost.

I believe these three accounts all have energy and capacity components and should be classified in like manner. I recommend all three be classified using the Idaho jurisdictional load factor in similar fashion to hydro and thermal production plant. The LF split classifies approximately 42% of the costs as demand related and approximately 58% of the costs as energy related. I recommend this as a package deal. All three of these cost categories are power supply costs and the costs are interrelated.

Seasonal Shapes included in Allocation Factors

Q. On pages 42 and 43 of his direct testimony Dr. Peseau includes two charts that show the effects of marginal cost weighting. Please comment on the charts.

A. My only comment on the two charts relates to the horizontal line that is called "non-weighted". My concern is that I would not want anyone to view either of the charts and conclude that allocation factors include no shape except that provided by marginal cost weighting. All of the energy and demand allocation factors proposed for use in this case capture the monthly shape of every individual classes energy and coincident peak demand. The only time this is not true is if the monthly weight is set at zero and the weighted and unweighted allocators are not

averaged. Data reflecting the shapes of the allocation factors, weighted and unweighted, for the classes are shown for the Base Case method on Company Exhibit No. 47. The shape of irrigation class energy and coincident peak demand is striking and shows why the irrigation class is allocated significant costs for use during the summer peak period.

The Department of Energy's Cost of Service Proposal

Q. Please discuss the Department of Energy's Cost of Service proposal presented by Dr. Goins.

A. Dr. Goins employs the Company's 3CP/12CP methodology but recommends different energy/demand classifications for major costs. He initially recommends that all production plant investment be classified as 100% energy related. To my knowledge this has never been done in Idaho. Coal and hydro plants cost more per kW to build than gas fired peaking units. The additional investment is made with the knowledge that energy can be produced at a lower cost from these plants when they are operated at a high capacity factor. Since the additional investment is incurred to reduce energy costs it is logical to allocate the investment as energy related.

Dr. Goins' fall back position, should his primary position be rejected, is that hydro investment should be considered to be 60% demand related and 40% energy related, that coal plant be classified to energy and demand based on

the Idaho Jurisdictional LF and that peaking plant investment be considered to be 100% demand related. His classification of hydro plant differs significantly from that previously used by the Commission.

He also proposes a 50/50 classification of all Account 555 purchased power costs. This classification is arbitrary because it is established with little or no supporting justification.

The Irrigators Cost of Service Proposal

Q. Please discuss the irrigators COS proposal presented by Mr. Yankel.

A. The irrigators present a very interesting proposal. Mr. Yankel's proposal is intended to overcome a cost of growth inequity that he identifies. According to Mr. Yankel the inequity occurs when the irrigation class is allocated some of the costs of growth when the class is not growing. My residential growth hypothetical example discussed previously in this testimony shows that he is correct in that growth related costs are allocated to the irrigators and to all other customer classes.

Q. Should the irrigators be protected from the costs of growth in other classes?

A. Irrigators and all other existing customers are already protected from some of the costs of growth because contributions are required under the Company's distribution

line extension policy that cover a portion of the costs of growth. Costs offset by contributions do not increase rates.

However, the COS analysis filed in this case address costs of growth not offset by contributions. All such costs are part of the costs included in the uniform system of accounts and allocated to all customer classes based on class usage characteristics. Most of the existing individual customers in the non-irrigation classes are no more responsible for growth related cost than the irrigators, yet, none are protected from the costs of growth. This is because rates have historically been averaged to include the cost to serve new customers and the cost to serve older existing customers. Existing irrigators whose loads have not grown have no more right to be protected from growth related costs than do residential or other existing individual customers whose loads have also not grown. In my view a COS methodology that singles out a specific class of customers for rate protection is inequitable and may be contrary to court rulings. Mr. Yankel's proposed allocation methodology only protects those existing customers taking service within a class that has little or no load growth. For all practical purposes the irrigators are proposing that existing customers be required to pay for all growth related cost caused by new

customers within their classes.

It is my opinion that if adequate contributions cannot be collected from new customers, a portion of load growth costs must be passed to all customer classes to assure equity. I do not know whether current law will allow a regulated utility to collect more growth related costs from new customers through up-front fees or to charge different rates based on date of service.

I oppose the use of the COS method proposed by the irrigators based on the equity and legal concerns discussed above.

Summary

Q. Please summarize your testimony.

A. In general I believe that the COS proposals presented by the high LF customers in this case serve their individual interests and do not improve COS results.

I continue to recommend the use of the Base Case COS method proposed in my direct testimony with the following exception. As discussed in this testimony, I am willing to accept the classification of all purchased power costs and opportunity sales revenues by the Idaho jurisdictional LF, but only if all three accounts or sub accounts are classified this way.

Load growth costs not offset by customer contributions are impacting all customer classes. Equity

requires these costs be spread to all classes.

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

A. Yes, it does.

Case No. IPC-E-07-08
Class Cost of Service Comparison Matrix
Direct Testimony Positions

Description	COS Used by Commission in Case No. IPC-03-13	Idaho Power	Commission Staff	Micron
Methodology	Base Case	3CP/12CP	Base Case	Base Case
Energy/Demand Classification				
Production Plant - Primary Position				
Hydro	LF - 44.74% Demand/55.26% Energy	LF - 41.47% Demand/58.53% Energy	LF - 41.47% Demand/58.53% Energy	LF - 41.47% Demand/58.53% Energy
Coal	LF - 44.74% Demand/55.26% Energy	LF - 41.47% Demand/58.53% Energy	LF - 41.47% Demand/58.53% Energy	LF - 41.47% Demand/58.53% Energy
Natural Gas	100% Demand	100% Demand	100% Demand	100% Demand
Production Plant - Alternative Position				
Hydro				
Coal				
Natural Gas				
Purchased Power (non-PURPA)	100% Energy	100% Energy	100% Energy	100% Energy
Purchased Power (PURPA)	94% Energy/6% Demand	97% Energy/3% Demand	97% Energy/3% Demand	LF - 41.47% Demand/58.53% Energy
Opportunity Sales Revenue	100% Energy	100% Energy	100% Energy	100% Energy
Allocators				
Prod. Demand - Hydro & Coal	D10	D10B (Base)	D10	D10
Unweighted Months Used	12	12	12	0
Non-Zero Weighted Months Used	5	0	6	3
Averaged	Yes	No	Yes	No
Prod. Demand - Natural Gas	D10 (Same as above)	D10P (Peak)	D10 (Same as above)	D10 (Same as above)
Unweighted Months Used		0		
Non-Zero Weighted Months Used		3		
Averaged		No		
Transmission Demand - D13	D13	D13	D13	D13
Unweighted Months Used	12	12	12	0
Non-Zero Weighted Months Used	3	12	12	3
Averaged	Yes	Yes	Yes	No
Energy - E10	E10	E10	E10	E10
Unweighted Months Used	0	12	12	0
Non-Zero Weighted Months Used	12	12	12	12
Averaged	No	Yes	Yes	No

Exhibit No. 123
Case No. IPC-E-07-8
K. Hessing, Staff
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Case No. IPC-E-07-08
Class Cost of Service Comparison Matrix
Direct Testimony Positions

Description	DOE	ICIP (Sch. 19)	Irrigators (Sch. 24)
Methodology	3CP/12CP	Base Case	Base Case
Energy/Demand Classification			
Production Plant - Primary Position			
Hydro	100% Demand	LF - 41.47% Demand/58.53% Energy	LF - 41.47% Demand/58.53% Energy
Coal	100% Demand	LF - 41.47% Demand/58.53% Energy	LF - 41.47% Demand/58.53% Energy
Natural Gas	100% Demand	100% Demand	100% Demand
Production Plant - Alternative Position			
Hydro	60% Demand/40% Energy		
Coal	LF - 41.47% Demand/58.53% Energy		
Natural Gas	100% Demand		
Purchased Power (non-PURPA)	50% Demand/50% Energy	100% Energy	100% Energy
Purchased Power (PURPA)	50% Demand/50% Energy	LF - 41.47% Demand/58.53% Energy	97% Energy/3% Demand
Opportunity Sales Revenue	100% Energy	100% Energy	100% Energy
Allocators			
Prod. Demand - Hydro & Coal	D10B (Base)	D10	D10
Unweighted Months Used	12	0	12
Non-Zero Weighted Months Used	0	6	6 (Weighted for Marginal Cost & Growth)
Averaged	No	No	Yes
Prod. Demand - Natural Gas	D10P (Peak)	D10	D10
Unweighted Months Used	0	(Same as Above)	(Same as Above)
Non-Zero Weighted Months Used	3		
Averaged	No		
Transmission Demand - D13	D13	D13	D13
Unweighted Months Used	12	0	12
Non-Zero Weighted Months Used	12	12	12 (Weighted for Marginal Cost & Growth)
Averaged	Yes	No	Yes
Energy - E10	E10	E10	E10
Unweighted Months Used	12	0	12
Non-Zero Weighted Months Used	12	12	12 (Weighted for Marginal Cost & Growth)
Averaged	Yes	No	Yes

Difference - Base Case to Residential Load Growth

Company Base Case
$15,697,500 added to Acct. 555.1

A	B	C	D	E	F	G	H	I	J	K	L
			Difference From Base								
Line No	Tariff Description	Rate Sch. No.	Sales MWh	Revenue From Rates $	All Other Revenue $	Operating Expense $	Rate Base $	Initial Revenue Requirement $	Revenue Requirement Increase $	Percentage Increase %	Increase in Average Rate ¢/kWh
	Uniform Tariff Rates:										
1	Residential Service	1	0	0	0	5,797,427	0	294,420,892	9,519,376	3.23%	0.192
2	Small General Service	7	0	0	0	243,388	0	17,745,713	399,643	2.25%	0.192
3	Large General Service	9S	0	0	0	3,611,934	0	137,759,729	5,930,795	4.31%	0.192
4	Large General Service	9P	0	0	0	406,937	0	14,429,072	668,191	4.63%	0.185
5	Dusk to Dawn Lighting	15	0	0	0	6,840	0	752,106	11,231	1.49%	0.190
6	Large Power Service	19	0	0	0	2,421,862	0	77,180,402	3,976,698	5.15%	0.185
7	Agricultural Irrigation Service	24	0	0	0	1,947,455	0	100,918,906	3,197,720	3.17%	0.208
8	Unmetered General Service	40	0	0	0	18,931	0	893,298	31,084	3.48%	0.190
9	Street Lighting	41	0	0	0	23,975	0	2,157,494	39,367	1.82%	0.210
10	Traffic Control Lighting	42	0	0	0	6,344	0	218,084	10,416	4.78%	0.190
	Special Contracts:										
11	Micron	26	0	0	0	772,704	0	22,919,124	1,268,780	5.54%	0.181
12	J R Simplot	29	0	0	0	207,573	0	5,825,478	340,834	5.85%	0.181
13	DOE	30	0	0	0	232,131	0	6,545,228	381,160	5.82%	0.177
14	***Total Idaho***		0	0	0	15,697,500	0	681,765,526	25,775,295	3.78%	0.192

Difference - Base Case to Residential Load Growth

Company Base Case
with $15,697,500 added to Acct. 555.1, and
adjusted allocation factors (D10, D13, E10)

A	B	C	D	E	F	G	H	I	J	K	L
			Difference From Base								
Line No	Tariff Description	Rate Sch. No.	Sales MWh	Revenue From Rates $	All Other Revenue $	Operating Expense $	Rate Base $	Initial Revenue Requirement $	Revenue Requirement Increase $	Percentage Increase %	Increase in Average Rate ¢/kWh
	Uniform Tariff Rates:										
1	Residential Service	1	222,750	0	1,756,698	11,313,801	13,119,725	294,420,892	17,537,024	5.96%	0.083
2	Small General Service	7	0	0	(51,620)	74,297	(418,692)	17,745,713	147,899	0.83%	0.071
3	Large General Service	9S	0	0	(611,117)	1,660,880	(4,766,636)	137,759,729	3,060,567	2.22%	0.099
4	Large General Service	9P	0	0	(71,877)	175,539	(566,922)	14,429,072	326,564	2.26%	0.091
5	Dusk to Dawn Lighting	15	0	0	(5,656)	(7,033)	(15,561)	752,106	(4,448)	-0.59%	(0.075)
6	Large Power Service	19	0	0	(418,171)	1,132,980	(2,962,315)	77,180,402	2,130,573	2.76%	0.099
7	Agricultural Irrigation Service	24	0	0	(352,932)	797,685	(2,917,097)	100,918,906	1,479,253	1.47%	0.096
8	Unmetered General Service	40	0	0	(16,696)	(21,732)	(42,609)	893,298	(14,259)	-1.60%	(0.087)
9	Street Lighting	41	0	0	(4,701)	11,193	(27,512)	2,157,494	22,231	1.03%	0.119
10	Traffic Control Lighting	42	0	0	(612)	4,978	(95)	218,084	9,167	4.20%	0.167
	Special Contracts:										
11	Micron	26	0	0	(138,112)	361,898	(892,140)	22,919,124	695,607	3.04%	0.099
12	J R Simplot	29	0	0	(37,232)	102,192	(211,713)	5,825,478	199,173	3.42%	0.106
13	DOE	30	0	0	(47,970)	90,821	(298,433)	6,545,228	185,944	2.84%	0.086
14	***Total Idaho***		222,750	0	(0)	15,697,500	(0)	681,765,526	25,775,295	3.78%	0.106

Difference - Base Case to Residential Load Growth

Company Base Case
with $15,697,500 added to Acct. 555.1, and
adjusted allocation factors (D10, D13, E10), and
increased residential revenue ($13,195,710)

A	B	C	D	E	F	G	H	I	J	K	L
			Difference From Base								
Line No	Tariff Description	Rate Sch. No.	Sales MWh	Revenue From Rates $	All Other Revenue $	Operating Expense $	Rate Base $	Initial Revenue Requirement $	Revenue Requirement Increase $	Percentage Increase %	Increase in Average Rate ¢/kWh
	Uniform Tariff Rates:										
1	Residential Service	1	222,750	13,195,710	1,756,698	11,313,801	13,119,725	294,420,892	(4,130,332)	-1.40%	(0.080)
2	Small General Service	7	0	0	(51,620)	74,297	(418,692)	17,745,713	147,899	0.83%	0.071
3	Large General Service	9S	0	0	(611,117)	1,660,880	(4,766,636)	137,759,729	3,060,567	2.22%	0.099
4	Large General Service	9P	0	0	(71,877)	175,539	(566,922)	14,429,072	326,564	2.26%	0.091
5	Dusk to Dawn Lighting	15	0	0	(5,656)	(7,033)	(15,561)	752,106	(4,448)	-0.59%	(0.075)
6	Large Power Service	19	0	0	(418,171)	1,132,980	(2,962,315)	77,180,402	2,130,573	2.76%	0.099
7	Agricultural Irrigation Service	24	0	0	(352,932)	797,685	(2,917,097)	100,918,906	1,479,253	1.47%	0.096
8	Unmetered General Service	40	0	0	(16,696)	(21,732)	(42,609)	893,298	(14,259)	-1.60%	(0.087)
9	Street Lighting	41	0	0	(4,701)	11,193	(27,512)	2,157,494	22,231	1.03%	0.119
10	Traffic Control Lighting	42	0	0	(612)	4,978	(95)	218,084	9,167	4.20%	0.167
	Special Contracts:										
11	Micron	26	0	0	(138,112)	361,898	(892,140)	22,919,124	695,607	3.04%	0.099
12	J R Simplot	29	0	0	(37,232)	102,192	(211,713)	5,825,478	199,173	3.42%	0.106
13	DOE	30	0	0	(47,970)	90,821	(298,433)	6,545,228	185,944	2.84%	0.086
14	***Total Idaho***		222,750	13,195,710	(0)	15,697,500	(0)	681,765,526	4,107,939	0.60%	0.044

Difference

Company Base Case

with $100,000,000 added to Acct. 340 - 346

A	B	C	D	E	F	G	H	I	J	K	L
			Difference from Base								
Line No	Tariff Description	Rate Sch. No.	Sales MWh	Revenue From Rates $	All Other Revenue $	Operating Expense $	Rate Base $	Initial Revenue Requirement $	Revenue Requirement Increase $	Percentage Increase %	Increase in Average Rate ¢/kWh
	Uniform Tariff Rates:										
1	Residential Service	1	0	0	(827)	(114,805)	40,011,652	294,420,892	5,437,351	1.85%	0.110
2	Small General Service	7	0	0	(139)	(20,459)	1,667,342	17,745,713	201,015	1.31%	0.097
3	Large General Service	9S	0	0	397	49,617	22,173,805	137,759,729	3,197,827	2.53%	0.104
4	Large General Service	9P	0	0	43	5,001	2,407,792	14,429,072	346,608	2.71%	0.096
5	Dusk to Dawn Lighting	15	0	0	(22)	(1,308)	10,881	752,106	(581)	-0.06%	(0.010)
6	Large Power Service	19	0	0	327	47,794	12,997,788	77,180,402	1,905,062	2.89%	0.089
7	Agricultural Irrigation Service	24	0	0	107	13,466	14,857,524	100,918,906	2,110,481	2.98%	0.137
8	Unmetered General Service	40	0	0	(10)	(1,616)	80,295	893,298	8,650	0.98%	0.053
9	Street Lighting	41	0	0	(39)	(4,490)	31,231	2,157,494	(2,919)	-0.14%	(0.016)
10	Traffic Control Lighting	42	0	0	(0)	(31)	29,964	218,084	4,161	2.21%	0.076
	Special Contracts:										
11	Micron	26	0	0	85	17,946	3,659,554	22,919,124	543,757	2.92%	0.077
12	J R Simplot	29	0	0	16	491	925,947	5,825,478	130,941	2.81%	0.070
13	DOE	30	0	0	61	8,394	1,146,224	6,545,228	174,809	3.25%	0.081
14	***Total Idaho***		0	0	(0)	(0)	100,000,000	681,765,526	14,057,162	2.28%	0.104

Exhibit No. 125
Case No. IPC-E-07-8
K. Hessing, Staff
01/04/08

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 4TH DAY OF JANUARY 2008, SERVED THE FOREGOING **REBUTTAL TESTIMONY OF KEITH HESSING,** IN CASE NO. IPC-E-07-8, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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SECRETARY

CERTIFICATE OF SERVICE