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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE PETITION OF IDAHO POWER COMPANY FOR MODIFICATION OF THE LOAD GROWTH ADJUSTMENT FACTOR WITHIN THE POWER COST ADJUSTMENT (PCA) METHODOLOGY	)	CASE NO. IPC-E-06-8

DIRECT TESTIMONY OF
STEVEN D. WEISS
ON BEHALF OF NW ENERGY COALITION

ORIGINAL

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Steven Weiss. I am employed by the NW Energy Coalition, 219 First Ave. South, Suite 100, Seattle, WA 98104.

Q. WHAT ARE YOUR POSITION AND RESPONSIBILITIES?

A. I am a Senior Policy Associate and frequently represent the Coalition in regulatory proceedings with the Bonneville Power Administration and in the State of Oregon. I am also an advocate for clean and affordable energy in many other forums including the NW Power and Conservation Council, Columbia Grid and the Oregon Legislature.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Masters in Science Education from Bucknell University in 1976 and a Bachelor of Arts in Physics and Math from the University of California at Berkeley in 1968. Previous professional experience includes employment as Assistant Professor at Clarion State College in Pennsylvania from 1975-79, and I was elected to the Board of Salem Electric (Co-op) four times from 1982-94. I also owned and operated a retail bicycle shop from 1980-96. I have been employed by the Coalition since 1994 and have participated in numerous Oregon, BPA and regional policy forums and rate cases. I also co-authored Oregon's electricity restructuring law (SB1149). My resume is included as Exhibit 301.

Q. HAVE YOU APPEARED BEFORE UTILITY REGULATORY COMMISSIONS IN OTHER PROCEEDINGS?

A. Yes, I have represented the Coalition in numerous dockets, including rulemakings. Examples in Oregon include Northwest Natural's filings regarding its Weather Adjusted Rate Mechanism (UG 152) and decoupling (UG 143), Portland General Electric's decoupling filing (UE 126), and Cascade Natural Gas Corporation's Conservation Alliance Plan, inclusive of a decoupling mechanism (UG 167). In Washington, I served as a witness for the Coalition in the 2004 Puget Sound Energy (PSE) rate case, focusing on rate design issues; and in the ongoing PSE gas decoupling rate case (UG-060267 & UE-060266). Also I have represented the Coalition in numerous Integrated Resource Planning Processes, as well as at workshops and conferences over the past dozen years.

Q. PLEASE SUMMARIZE THE CONTENTS OF YOUR TESTIMONY.

A. My testimony is arranged as follows: (1) I first discuss how traditional ratemaking impacts the utility's (and customers') incentives and risks between rate cases. (2) Second I describe the effect on Idaho Power's net revenues resulting from each new kWh and each new customer hookup. (3) I then discuss how the policy implications of the PCA cannot be discussed in a vacuum. On this point, I believe the PCA issues at stake here are linked to the outcome of the decoupling proposal in IPC-E-04-15 (a proposal that essentially guarantees that Idaho Power's recovery of fixed costs for existing customers regardless of changes in their loads, and would allow the Company's fixed cost recovery to grow along with growth in customer numbers). (4) Finally, I will make a proposal that, assuming a decoupling mechanism is approved in

IPC-E-04-15, will lead to a revenue-neutral proposal regarding new customer *numbers*, while providing an incentive for IPC to encourage reduced *usage per customer.* By modifying Idaho Power's proposal in this case, and approving a decoupling mechanism in IPC-E-04-15, the Commission would both maintain traditional shared risks, while also creating a strong incentive for the utility to fully obtain and advocate for conservation and efficiency improvements, which are by far the least-cost resources available to customers. Currently Idaho Power likely enjoys net positive revenues from load growth, providing both a disincentive to the Company to promote conservation and an unwarranted windfall unrelated to its actions. To reflect that fact in the PCA, a Load Growth Adjustment must be added, but the methodology must be different than presently used. The scope of my testimony does not include a specific recommended amount, but does provide an example of how that could be developed.

I. Traditional Ratemaking

Q. WHAT INCENTIVES AND DISINCENTIVES ARE EMBEDDED IN TRADITIONAL UTILITY REGULATION AND WHAT EFFECT DO THEY HAVE?

A. Utilities have traditionally been regulated based on their costs, including an opportunity to earn a reasonable rate of return. In periodic rate cases, a review of revenue and cost levels occurs, and rates determined such that the utility can earn that rate of return. But just as important an element of regulation is how the rate structure, and any trackers, affects the Company *between* rate cases. This is known as Regulatory Lag. For it is between rate cases that any reduction in costs and/or increase in revenues go straight to the utility's bottom line. Thus the incentives provided by the rate structure are important motivators for utility actions.

Regulatory lag, in my opinion, is one of the most important considerations regulators should be aware of when designing or approving rates. On the cost side, regulatory lag is largely beneficial for customers because it provides the utility the incentive to reduce costs and improve productivity, which are then incorporated into lower rates in the next rate case.[1] But on the revenue side, the issue is more complicated. That is because regulatory lag can produce utility incentives that are at cross-purposes with customer interests, promote unabated load growth and lead ultimately to higher costs.

Q. WHAT FACTORS INFLUENCE REVENUES BETWEEN RATE CASES?

A. Broadly, two factors are important: (a) changes in revenue per customer from load changes; and, (b) changes in the number of customers. To understand the utility's incentives, it is necessary to determine what the financial impact to the utility is from increases or decreases in these two factors. Revenue per customer between rate cases has two determinants: First is change in *usage per customer* multiplied by the marginal rate for that customer. Second is change in the *number* of customers.

All ratemaking regulation provides utilities with incentives or disincentives to behave in a certain manner. By focusing on how the addition (or reduction) of one kWh of load or one new customer affects the utility's bottom line between rate cases, one can describe those incentives and disincentives. In addition, one can see if the rate structure causes undeserved increases or decreases in a utility's net revenues that

[1] This is not an unalloyed benefit. Many regulators also require utilities to have in place strong service quality and reliability standards to ensure that cost-cutting is not over done.

are unrelated to the utility's actions. Such a result is simply an undeserved loss or windfall to the utility, and even if symmetric (i.e., equally likely to benefit shareholders or customers over the long term) may increase net revenue volatility unnecessarily.[2] Ideally, utilities should be rewarded based on how well they meet their customers' energy service needs, but that is not always the case. Sometimes the utility's incentive is to encourage load growth even though cost-effective conservation would be less costly to customers. (This issue is thoroughly covered in the decoupling discussion in IPC-E-04-15, so I will not repeat it here.) And sometimes the utility is rewarded or punished with windfall profits or losses unrelated to its activities. Thus it is important to examine the issue closely in order to have a result that is fair to all parties and in the public interest

II. The Effect of Marginal Changes in Load and Customer Count

Q. WHAT HAPPENS TO IPC'S NET REVENUES UNDER CURRENT POLICY WHEN LOAD INCREASES BY 1 KWH?

A. For this discussion, I first assume that this increase in load is not accompanied by a higher customer count and that it is a residential load (and, of course, decoupling has not been implemented). Perhaps someone adds a battery charger after the rate case has set load levels. Below I address a scenario where the load growth occurs from the addition of a customer.

[2] For example, changes in weather, totally out of the utility's control, can produce volatility in its returns that serve no purpose other than simply raising its cost of capital—a cost that must eventually be paid by customers. A weather decoupling mechanism, however, can reduce that volatility.

A number of things determine how much IPC's net revenue changes. First, its revenues increase by about 6.5¢, because that is how much extra the customer pays for the kWh.[3] But its costs also increase, and this is where it gets a little complicated. To serve this new load, Idaho Power must either purchase the electricity from the market (or forego the same amount of money from reduced sales). Let's assume for discussion a market price of 4¢ ($40/MWh—note: all prices per MWH have been converted to cents/kWh in this discussion). While a portion of those costs would be covered by the PCA, I will put aside the PCA for the moment and focus on what it really costs the Company.

In addition to the 4¢ for additional power, the Company also incurs some incremental "fixed" costs. While the embedded costs of its hydro and coal facilities won't change, each additional increment of load will incur an incremental cost for additional O&M, bigger or more numerous transformers, substations, etc.—i.e, that kWh's share if incremental distribution costs. But, for the most part, these distribution costs will not increase between rate cases, especially in this scenario where the load growth is not associated with a new customer. The system is built robustly enough that incremental load growth in existing neighborhoods will not increase distribution and O&M costs much. The "robustness" (i.e. the headroom available to accommodate load growth) has already been included in the capital costs of the system, which will not change. Larger distribution costs, such as new substations and larger transformers may eventually be needed if average loads increase substantially, but their costs will be added into rate base at the next rate case.

[3] I have assumed that the additional kWh is priced at the higher, marginal block rate.

So though I cannot precisely say how much new distribution costs the new kWh will cause, it most likely is less than 0.5¢. An exact number is not important for my point.

My point is that it is very likely that the costs of serving the new kWh will not match the added revenue from that kWh. In my example, the additional costs totaled 4.5¢ while the additional revenue was 6.5¢. In this likely situation, the Company will see an increase in its net revenue of 2¢ and thus have a powerful incentive to encourage increased load and to be less-than-enthusiastic about conservation.

Q. WHAT HAPPENS TO IDAHO POWER'S NET REVENUES WHEN IT ADDS A NEW CUSTOMER?

A. I will assume for this example that this is a residential customer, and his or her load is exactly the same as the average of all other customers.

This customer's load also pays about 6.5¢ for each kWh. (Not exactly true due to Idaho Power's 2-block rate plus the customer charge, but close enough for this discussion.) For each kWh used by this customer, Idaho Power's power cost is about 4¢ as in the previous example. But because this is a new hook-up, the Company's added distribution costs are higher than in that case. The Company has to string wire, install a new meter and perhaps a (portion of) a new transformer—all between rate cases. Ignoring any construction costs paid by the new customer due to IPC's line extension policy, perhaps this costs 2¢ per kwh for the average new customer. IPC therefore receives 0.5¢ in net revenues. So now, the mismatch between cost and revenue is less than the first scenario (0.5¢ on each new kWh compared to 2¢). That would reduce the utility's incentive to increase loads from new customers compared to the previous example, but it would still exist.

Q, PLEASE SUMMARIZE YOUR CONCLUSION THUS FAR.

A. Putting aside regulatory treatment of all this, I draw two conclusions. (a) If the incremental cost of increased load or increased customers does not match the incremental net revenue produced, the utility will have incentives that may or may not be in the public interest; and, (b) the critical numbers one must look out to understand what is really happening are the *incremental* costs (and revenues) of new load and new customers, not the embedded costs.

Q. PLEASE EXPLAIN THE CURRENT REGULATORY TREATMENT OF THE TWO SCENARIOS DISCUSSED ABOVE.

A. The two regulatory mechanisms that bear on this issue are the PCA and any decoupling mechanism that might be approved. I will start with the PCA.

The first thing to point out is that the PCA is not affected by customer count. Therefore the PCA impact is the same for any increase in load regardless of whether it came from an existing or new customer—the PCA only adjusts the power cost impact, but does not address the different distribution cost impacts of the two scenarios. Therefore, the PCA cannot provide an appropriate regulatory impact for both scenarios at the same time, since the PCA treats these two scenarios—though they have quite different net revenue impacts – as if they were the same. Second, the PCA formula depends on embedded costs. The added base rate revenue from each additional kWh is partly allocated toward PCA costs (about 0.7¢ and the rest to non-PCA costs). Yet it is clear that the *incremental* power cost to serve the new load is higher, in the 4¢ or more range, and the *incremental* fixed cost is different in the two scenarios (and certainly much less than the embedded fixed cost).

In short, the PCA adjustment is not linked to the *actual incremental* changes in costs and revenues that I went through above. Only by extraordinary luck could it avoid a result that either rewards or punishes IPC for new loads and/or new customers due to the almost inevitable mismatch between the incremental costs and revenues that result from growing loads. The result—either a reward or a penalty—becomes the incentive to either encourage or discourage load growth. I believe it is poor public policy to have this key result driven by the arbitrary and essentially random differences between the incremental costs of serving new loads and customers.

Currently the PCA reduces the amount the utility can recover from its additional power costs by about 1¢/kwh (using the current $16.84/MWh load growth adjustment minus the $6.71/MWh embedded PCA cost). Gregory Said's direct testimony (p. 12) describes a "penalty" of around 1.16¢/kWh using older numbers, but the calculation is the same. As I estimated above, without the PCA the Company's actual net revenues increase by 2¢/kWh for load growth of existing customers, so including the PCA would probably result in the Company still having a positive incentive of 1¢/kWh to increase load. But for new customers, the PCA would penalize the Company through a net revenue loss of 0.5¢/kWh. Clearly this is a bizarre result. IPC is proposing to remove this "penalty," which would mean all load growth would benefit the Company.

Q. DO YOU AGREE WITH THE COMPANY THAT THE PRESENT PCA PENALIZES IDAHO POWER FOR LOAD GROWTH?

A. Seen in isolation, it would seem that way. However, the PCA only deals with the cost of new power, not the cost of incremental distribution nor the effect of increased revenue. In addition there is another reason to suspect that it is not really a penalty. If it really were true that the Company was not allowed to recover a significant amount of money because of load growth, one would expect it to be aggressively pursuing conservation. Sadly, that is not really the case.

Q. DOES IDAHO POWER'S INVESTMENT IN DEMAND-SIDE MANAGEMENT OVER THE LAST DECADE EVINCE A COMPANY THAT SUFFERS A PENALTY FROM GROWING LOADS?

A. No. Idaho Power has been very slow to implement demand-side management, even in the face of growing loads. Idaho Power's system load in its 1994 rate case was about 14.5 million MWh's. The Company's system load increased over the next six (6) years up to a high point of about 15.8 million MWh's in 2000-2001. Over that same six (6) year period, Idaho Power's spending on demand-side management dropped precipitously from about $6.19 million in 1995 down to about $1.7 million in 2000 and 2001. In response to the energy crisis of 2000-01, system loads dropped before resuming their growth. See Exhibits 302 at pages 2, 5 (Idaho Power Response to Production Requests).

Q. WHY DO YOU BELIEVE THOSE FACTS ARE IMPORTANT?

A. The fact that Idaho Power dis-invested in DSM in the late 1990's in the face of growing loads indicates that the Company is not penalized enough by the Load Growth Adjustment in the PCA, as indicated in the Direct Testimony of Gregory Said (page 12) to overcome the underlying marginal increase in the net revenues it receives from adding load. If there was a detectable penalty in the PCA (as part of Idaho Power's overall rate design), the Company was behaving irrationally.

Q. IS IDAHO POWER INVESTING IN ENOUGH DSM TODAY?

A. NW Energy Coalition believes the Idaho Power is rapidly improving its DSM program. I understand that the Company's draft 2006 Integrated Resource Plan proposes to further accelerate DSM program investments nearly up to the approximately levels of DSM potential estimated by the Northwest Power and Conservation Council in 2004. That said, the Company's actually estimated savings are still very low (3.25 MWa in 2004, and 4.71 MWa in 2005, both including estimated savings from programs run by Northwest Energy Efficiency Alliance). Exhibit 302 at page 9. I am certain those savings will accelerate rapidly in coming years, but they are still low compared to other Northwest utilities. It is NW Energy Coalition's position that all cost-effective DSM resources should be acquired before supply resources are acquired. Very simply, there is no easier, cheaper, or cleaner way to keep both rates and customer bills low.

Q. GIVEN THIS WEAK RECORD ON CONSERVATION, IS THE COMPANY BEHAVING IRRATIONALLY?

A. No. As I noted above, even with the PCA's "penalty," the Company likely has an incentive to promote load growth, especially by existing customers. Therefore it is serving its shareholders well by having a lukewarm attitude toward conservation, even though it is compensated completely for its conservation costs.

Q. WHAT IS YOUR CONCLUSION REGARDING THE PCA?

A. The PCA, as presently designed, can never result in rates that are exactly "right" in balancing the impact of new load on the Company. But because of that mismatch, it is never neutral. Instead it provides an incentive (for or against load growth) depending on the level of the load growth adjustment. If the Commission wishes to provide Idaho Power an incentive toward conservation by providing a penalty, it should do so directly. I do not believe the Commission should address this important policy issue obliquely through the load growth adjustment.

Q. WHAT WOULD BE A BETTER DESIGN FOR A PCA ADJUSTMENT?

A. A better design would be ensure the PCA has a neutral impact by reflecting as close as possible the actual incremental changes in costs and revenues that load growth and new customer growth creates. That is, the PCA should reimburse the Company for (90%[4] of) the *incremental* cost of new power, less the *incremental* revenues received from the customer, rather than relying on embedded costs that have little relation to the actual net revenue impacts. That calculation would necessarily be different for the two scenarios examined—load growth from existing customers versus load growth from new customers—because they have different incremental revenues. Therefore there would be two different PCA adjustments: one for load growth from existing customers, and the other for load growth from new customers.[5] This design is neutral to the Company in that it does not provide any incentive or disincentive to encourage load growth. If the Commission wishes to provide an incentive for the Company to reduce load growth, it should do so directly, and not rely upon this opaque mechanism to achieve that policy result.

Q. IS YOUR SUGGESTION FOR MANY DIFFERENT ADJUSTMENT FACTORS TOO COMPLICATED?

[4] If the Commission wishes to provide a stronger incentive to the Company to make smart purchases between ratecases, it could lower this percentage.

[5] These two would apply to residential customers. Different adjustments would also have to be used for the other customer classes.

A. I don't believe that two factors for each customer class is all that complicated. However, a second best solution is to set the load growth adjustment rate such that the PCA results in an adjustment that reflects the average incremental change that load growth causes for each class, and not differentiate between new and existing customers. There should still be a different adjustment for each other customer class, however, as the incremental cost changes for commercial and industrial load increases are quite different than for residential customers.

Q. COULD YOU PROVIDE AN EXAMPLE USING THE NUMBERS YOU HAVE BEEN USING SO FAR?

A. Yes. Please note that this example does not assume a decoupling adjustment. I assumed that a new kWh to serve an existing residential customer was acquired at a cost of 4¢. That new kWh produced incremental revenues for the Company of 6¢ (rate of 6.5¢ minus the incremental increase in distribution costs of 0.5¢). Without a PCA, the utility would enjoy a windfall of 2¢. Therefore the load growth adjustment must be set at a level that produces a refund to customers of 2¢ (this would calculate to $26.71/MWh, or $20/MWh plus the $6.71/MWh embedded PCA amount). Using this amount as the adjustment makes the Company neutral in regard to load growth from existing customers. A different load growth adjustment can similarly be designed for the case of load growth due to a new customer hookup. Using my example, it would be $11.71 ($5 + $6.71).

Q. COULD THE COMMISSION USE YOUR DESIGN TO SHIFT LOAD GROWTH RISK TO THE COMPANY?

A. Yes. If the Commission wanted the PCA to provide a stronger incentive to the utility for pursuing conservation, it could raise the load growth adjustment higher so as to penalize the company when load growth occurs. Another effective way to motivate the Company that we favor is to set concrete DSM targets and benchmarks connected to rewards and penalties.

Q. THE SECOND MECHANISM THAT HAS AN IMPACT ON THIS ISSUE IS DECOUPLING. HOW DOES DECOUPLING AFFECT THE TWO SCENARIOS?

A. While the PCA addresses changes in power costs between rate cases, decoupling addresses changes in fixed costs. Under the decoupling proposal being discussed in IPC-E-04-15, revenue changes between rate cases resulting from loads being higher or lower than normal for *existing* customers are adjusted to provide the Company with the same embedded fixed costs per customer as approved in the most recent rate case. As such, the mechanism is neutral in relation to existing customers and provides neither an incentive nor disincentive for IPC to encourage load growth (or promote conservation). In addition, the proposed decoupling mechanism would also maintain that same average level of embedded non-power related costs for new load created by new hookups regardless of their usage level. However, the incremental non-power costs of serving a new customer are most likely lower than the embedded cost imputed to existing customers of about 3.25¢/kwh.[6] That is because the incremental cost of serving a new customer is just the cost of additional distribution. There is no additional impact to the other embedded costs of the system such as

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[6] The non-power costs of about $138 million are divided into average usage of about 4.5 billion kWh. I obtained these figures from the direct testimony of Mike Youngblood in the decoupling docket (IPC-E-04-15) pp.14-16.

generation costs and other debt. Thus, the Company will receive a windfall from new customers (regardless of their usage) by recovering average embedded fixed costs rather than the much smaller incremental amount. So while the mechanism does indeed remove the incentive to encourage load growth, it is not neutral. It provides an incentive to hook up more customers. (A discussion of whether or not this is a desired outcome is not part of this proceeding, however.)

Q. MODIFYING THE DECOUPLING PROPOSAL IS NOT A SUBJECT OF THIS DOCKET, HOW IS IT RELEVANT TO THIS DISCUSSION?

A. It is important for the Commission to understand the connection between the PCA discussion and the decoupling discussion. The incentive the Company will see, and the overall fairness of the rates, depends on how they are both designed.

In summary, it is necessary to look at the complete package. It is impossible to understand how the PCA and decoupling mechanisms will reward or penalize Idaho Power for pursuing and encouraging conservation without looking at their combined effects on marginal changes in load.

Q. DOES THE COALITION HAVE A RECOMMENDATION?

A. Yes.

1. We recommend that the PCA be redesigned so that it is based on the different incremental costs of load growth caused by existing customers versus load growth caused by new customers, thus making it neutral to the Company and customers. In the alternative, the load growth adjustment should be set to come as close to that result as possible. I have provided an example of how that could be done. All that is missing to do the calculation are estimates of the incremental

costs of serving new load and new customers based on Idaho Power's system data. Staff and the Company are best equipped to identify those numbers.

2. To provide the Company with a clear incentive to encourage conservation: (a) decoupling should be approved in order to remove the disincentive on the revenue side; <u>and</u>, (b) either: (i) raise the load growth adjustment another $10.00 or so from the number determined in #1 above to provide a clear incentive for conservation; or, (ii) use direct conservation targets and benchmarks with incentives and penalties.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CERTIFICATE OF SERVICE

I hereby certify that on this 15TH day of September 2006, true and correct copies of the foregoing DIRECT TESTIMONY OF STEVE WEISS were delivered to the following persons via the method of service noted:

Via Hand-Delivery:

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Steven Weiss

Current Position	Senior Policy Associate, NW Energy Coalition
Experience	1995 - Present NW Energy Coalition Seattle, WA **Senior Policy Associate** • Sr. member of the policy team implementing NWEC's policy goals relating to a clean and affordable energy future. • Areas of responsibility include Bonneville Power Administration, Oregon PUC, Oregon Legislature, NW Power Planning Council, Grid West/Columbia Grid,, Oregon Advisory Committee on Energy (low-income issues), occasional DC lobbying.
	1993-1995 Clients: NW Energy Coalition, OR Dept. of Energy, WA Utilities and Transportation Commission **Consultant** • Policy development and advocacy on Regional energy issues. • Published newsletter on BPA's Power Sales Contract Negotiations.
	1984-1996 Salem Electric Co-op Salem, OR **Director** – Elected to four 3-year terms • Chair, 1989-91 • Initiated, or major co-sponsor of the following initiatives: • Inverted residential rates • Low-income energy assistance program • Efficient appliance rebates, recycling rebates, at-cost CFLs, etc. • Salem Electric "Building Code" which gives builders incentives for efficient building practices. • Integrated Resource Planning. • Representative to NWPPA, PPC, NRECA
	1980-1996 Bicycle Doctors bicycle shops Salem, OR **Owner** – 2 stores • Staff of 8 • Sales of $450,000 annually
	1971-1985 **Instructor/Professor** • 1971-1977 Physics Instructor, Bucknell University • 1977-1979 Assistant Professor, Clarion State College. Research and teaching on campus demonstration high school. • 1980-1985 Math/statistics instructor (part-time), Chemeketa Community College, Salem, OR

	2003-Present **Board of Directors** • Elected to Citizens' Utility Board board of directors, 2002 and 2005
Regulatory and other Policy Experience	Prepared testimony and participated as key Witness for NW Energy Coalition: • 1996, 2001, 2002, 2006 Bonneville Power Administration ratecases • Numerous BPA proceedings including Power Function Review, Resource Adequacy Forum, Comprehensive Review, Subscription process, Regional Dialogue, etc. • 1998, 2000, 2003, 2006 PacifiCorp and Portland General Electric Integrated Resource Planning dockets. • 1996 docket on purchase of PGE by Enron • 1999 docket on purchase of PacifiCorp by Scottish Power • 2001 PGE decoupling docket • 2001 PacifiCorp and PGE restructuring dockets following passage of SB1149 • 2002 UM1066 docket on Regulatory Policies affecting resource development • 2002 NW Natural dockets establishing decoupling, public purpose charges • 2004 Puget Power gas and electric docket on rate design • 2005 Oregon dockets on competitive bidding, and Least Cost Planning requirements • 2004-5 Oregon dockets instituting decoupling/public purposes for Cascade Natural Gas Lead negotiator for NW Energy Coalition: • 1996 BPA contract negotiations on tiered rates • Development of Grid West (RTO) • 2001 BPA's "Safety-Net" rate adjustments • 2002-05 BPA's Regional Dialogue
Education	• 1968 BA Physics and Math, Univ. of California, Berkeley • 1975 MS Education, Bucknell Univ., Lewisburg, Pennsylvania
Accomplishments with NW Energy Coalition	• 1997, 1999 Oregon Legislative sessions -- Co-authored and lobbied to pass SB 1149, Oregon's electricity restructuring law. • Co-founded the Fair and Clean Energy Coalition, Oregon public interest lobbying coalition • Expert witness in numerous Oregon PUC dockets and rulemakings, including proposals to decouple PGE and NW Natural's distribution rates, least-cost plans, etc. • Expert witness in BPA rate cases, including developing rate adjustment mechanisms now part of the agency's rates. • Environmental representative to GridWest development group. Filed testimony and comments to FERC on RTO West and other transmission and market issues. • Serve on Governor's Advisory Committee on Energy which advises Oregon agencies on low-income issues. Served on Portfolio Advisory Committee which develops portfolio choices for Oregon consumers under SB 1149. Serve on Energy Trust of Oregon's Conservation Advisory Council. • Provide analysis and coordination with salmon advocates and tribes relating to energy/salmon issues.

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE PETITION OF IDAHO POWER COMPANY FOR MODIFICATION OF THE LOAD GROWTH ADJUSTMENT RATE WITHIN THE POWER COST ADJUSTMENT METHODOLOGY	)	CASE NO. IPC-E-06-08 IDAHO POWER COMPANY'S RESPONSE TO THE FIRST PRODUCTION REQUEST OF NW ENERGY COALITION TO IDAHO POWER COMPANY

COMES NOW, Idaho Power Company ("Idaho Power" or "the Company") and, in response to the First Production Requests of NW Energy Coalition to Idaho Power Company dated August 8, 2006, herewith submits the following information:

EXHIBIT
302

REQUEST FOR PRODUCTION NO. 1:

Please state Idaho Power company's normalized system loads for each year starting with year 1995 through 2005.

RESPONSE TO REQUEST FOR PRODUCTION NO. 1:

Idaho Power company's normalized system loads for 1995 through 2005 in MWh's are as follows:

1995	14656029
1996	15141574
1997	15180588
1998	14758836
1999	15240817
2000	15837958
2001	15759779
2002	14276689
2003	14193837
2004	14536634
2005	14819152

The response to this request was prepared by Gregory W. Said, Manager of Revenue Requirement, Idaho Power Company, in consultation with Barton L. Kline, Senior Attorney, Idaho Power Company.

REQUEST FOR PRODUCTION NO. 2:

Please explain the basis for Witness Greg Said's use of normalized system load to calculate the current embedded PCA-related cost of serving load (which he states to be $6.81/MWh), as opposed to using normalized firm system sales to calculate the same figure..

RESPONSE TO REQUEST FOR PRODUCTION NO. 2:

The Load Change Adjustment, as calculated in the Company's PCA Deferral Report is based upon the change from Normalized System Load to Actual System Load. It would be inappropriate to use an adjustment rate based upon sales unless the growth measured was also based upon sales, i.e. a sales change adjustment rather than a load change adjustment. Please also see the Company response to Staff Request for Production No. 3.

The response to this request was prepared by Gregory W. Said, Manager of Revenue Requirement, Idaho Power Company, in consultation with Barton L. Kline, Senior Attorney, Idaho Power Company.

REQUEST FOR PRODUCTION NO. 3:

Please state Idaho Power Company's current average unit cost of serving load growth.

RESPONSE TO REQUEST FOR PRODUCTION NO. 3:

From the Company's perspective average unit cost is synonymous with embedded cost. As stated in Mr. Said's testimony, the current embedded PCA related cost of serving load is $6.81 per MWh.

The response to this request was prepared by Gregory W. Said, Manager of Revenue Requirement, Idaho Power Company, in consultation with Barton L. Kline, Senior Attorney, Idaho Power Company.

REQUEST FOR PRODUCTION NO. 4:

Please state Idaho Power Company's total amount of spending on demand-side management ("DSM") programs or initiatives (including payments to the Northwest Energy Efficiency Alliance ("NEEA") for each year starting with year 1995 through 2005.

RESPONSE TO REQUEST FOR PRODUCTION NO. 4:

The following table details Idaho Power Company's total amount of spending on demand-side management ("DSM") programs or initiatives (including payments to the Northwest Energy Efficiency Alliance ("the Alliance")) for each year starting with year 1995 through 2005 as provided in the Company's respective DSM Annual Reports (previously termed Conservation Plan) filed with the Commission.

	Total System (nominal $)
1995	$6,186,558
1996	$4,350,128
1997	$3,189,173
1998	$2,681,668
1999	$2,127,840
2000	$1,609,217
2001	$1,694,314
2002	$2,143,103
2003	$2,482,972
2004	$3,707,280
2005	$6,700,973

Notes:
Expenses are reported on a cash basis.

The response to this request was prepared by Tim Tatum, Senior Analyst, Idaho Power Company, in consultation with Barton L. Kline, Senior Attorney, Idaho Power Company.

REQUEST FOR PRODUCTION NO. 5:

Please state an estimate of Idaho Power Company's expected total amount of spending on DSM programs or initiatives (including payments to NEEA) in 2006.

RESPONSE TO REQUEST FOR PRODUCTION NO. 5:

Idaho Power Company's expected total amount of spending on DSM programs or initiatives (including payments to the Alliance) in 2006 is $12,670,000.

The response to this request was prepared by Tim Tatum, Senior Analyst, Idaho Power Company, in consultation with Barton L. Kline, Senior Attorney, Idaho Power Company.

REQUEST FOR PRODUCTION NO. 6:

Please state the total amount collected by Idaho Power Company under Schedule 91 ("Energy Efficiency Rider") for each year starting with year 2002 through 2005.

RESPONSE TO REQUEST FOR PRODUCTION NO. 6:

The total amount collected by Idaho Power Company under Schedule 91 ("Energy Efficiency Rider") on a system basis for each year starting with year 2002 through 2005 is provided in the following table.

Idaho Power Company
DSM Rider Funds - GL Account 254201 & 254202
Idaho & Oregon Yearly Data from 2002-2005

	2002	2003	2004	2005	2002-2005 Total	
Idaho Rider						
Funding	1,577,984.92	2,587,753.98	2,647,832.11	5,761,727.43	12,575,298.44	
Interest	14,063.85	42,044.19	39,507.40	105,269.71	200,885.15	
Idaho Total	**1,592,048.77**	**2,629,798.17**	**2,687,339.51**	**5,866,997.14**	**12,776,183.59**	
Oregon Rider						
Funding				101,742.42	101,742.42	
Interest				3,475.08	3,475.08	
Oregon Total				**105,217.50**	**105,217.50**	**

**Oregon Rider approved in August 2005. In August 2005, $141,089.64 was transferred into the rider account from a deferrral account. Year end available funding balance was $246,307.14.

The response to this request was prepared by Tim Tatum, Senior Analyst, Idaho Power Company, in consultation with Barton L. Kline, Senior Attorney, Idaho Power Company.

REQUEST FOR PRODUCTION NO. 7:

Please state an estimate of Idaho Power Company's expected total collections under the Energy Efficiency Rider in 2006.

RESPONSE TO REQUEST FOR PRODUCTION NO. 7:

Idaho Power Company's expected total collections under the Energy Efficiency Riders in Idaho and Oregon in 2006 is approximately $8,740,979 based upon forecasted normalized sales . Idaho customers are expected to provide approximately $8,334,415 and $406,564 is expected from Oregon customers.

The response to this request was prepared by Tim Tatum, Senior Analyst, Idaho Power Company, in consultation with Barton L. Kline, Senior Attorney, Idaho Power Company.

REQUEST FOR PRODUCTION NO. 8:

Please state the total amount of estimated energy savings (expressed as average megawatts) Idaho Power Company and its customers have achieved as a result of DSM programs (including any savingsj achieved as a result of NEEA programs) for each year starting with year 1995 through 2005.

RESPONSE TO REQUEST FOR PRODUCTION NO. 8:

The following table details the total amount of estimated energy savings (expressed as average megawatts) Idaho Power Company and its customers have achieved as a result of DSM programs (including any savings achieved as a result of Alliance programs) for each year starting with year 1995 through 2005 as provided in the company's respective DSM Annual Reports (previously termed Conservation Plan) filed with the Commission.

Year	Annual Energy Savings excluding Alliance (Mwa)	Alliance Reported Energy Savings * (Mwa)	Total Annual Energy Savings (Mwa)
1995	4.72		4.72
1996	3.65		3.65
1997	1.94		1.94
1998	1.87		1.87
1999	0.24		0.24
2000	0.02		0.02
2001	0.05		0.05
2002	0.51		0.51
2003	0.67		0.67
2004	0.9	2.36	3.26
005	2.42	2.29**	4.71

Notes:
*Alliance Savings not available prior to 2004. The Alliance savings based on regional load allocation percentage of 6.5%.
**Preliminary estimate from the Alliance, February 24, 2006

The response to this request was prepared by Tim Tatum, Senior Analyst, Idaho Power Company, in consultation with Barton L. Kline, Senior Attorney, Idaho Power Company.

REQUEST FOR PRODUCTION NO. 9:

Please state the total amount of estimated energy savings (expressed as average megawatts) Idaho Power Company and its customers are expected to achieve as a result of DSM programs (including any savings achieved as a result of NEEA programs) in 2006.

RESPONSE TO REQUEST FOR PRODUCTION NO. 9:

Idaho Power Company and its customers are expected to achieve energy savings of approximately 3.6 average megawatts in 2006 as a result of DSM programs. This estimate does not include savings achieved as a result of Alliance programs as such estimate is not available to Idaho Power at this time.

The response to this request was prepared by Tim Tatum, Senior Analyst, Idaho Power Company, in consultation with Barton L. Kline, Senior Attorney, Idaho Power Company.

REQUEST FOR PRODUCTION NO. 10:

Please provide any studies, reports, memoranda, or similar analyses which estimate the potential energy or peak demand savings which may be achievable through DSM programs in Idaho Power's service territory.

RESPONSE TO REQUEST FOR PRODUCTION NO. 10:

Idaho Power objects to this request on the grounds that it does not specify any timeframe for producing studies, reports, etc. This objection notwithstanding, the enclosed CD contains copies of the studies, reports, etc. addressing the Company's most recent estimates of DSM potential.

The response to this request was prepared by Tim Tatum, Senior Analyst, Idaho Power Company, in consultation with Barton L. Kline, Senior Attorney, Idaho Power Company.

DATED this 5th day of September, 2006, at Boise, Idaho.

BARTON L. KLINE
Attorney for Idaho Power Company