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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE INVESTIGATION OF FINANCIAL DISINCENTIVES TO INVESTMENT IN ENERGY EFFICIENCY BY IDAHO POWER COMPANY.	)	CASE NO.IPC-E-04-15

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

RALPH CAVANAGH

Q. Please state your name, address, and employment.

A. My name is Ralph Cavanagh. I am the Energy Program Director for the Natural Resources Defense Council ("NRDC"), 71 Stevenson Street #1825, San Francisco, CA 94105.

Q. Please outline your educational background and professional experience.

A. I am a graduate of Yale College and Yale Law School, and I joined NRDC in 1979. I am a member of the faculty of the University of Idaho's Utility Executive Course, and I have been a Visiting Professor of Law at Stanford and UC Berkeley (Boalt Hall). From 1993-2003, I served as a member of the U.S. Secretary of Energy's Advisory Board. My current board memberships include the Bonneville Environmental Foundation, the Center for Energy Efficiency and Renewable Technologies, the Energy Center of Wisconsin, the National Commission on Energy Policy, the Renewable Northwest Project, and the Northwest Energy Coalition. I have received the Heinz Award for Public Policy (1996) and the Bonneville Power Administration's Award for Exceptional Public Service (1986). I first appeared before the Idaho Public Utilities Commission in 1987 as a Commission Staff-sponsored witness on energy conservation issues in Case No. U-1500-165 and, most recently in 2004, as a witness for the Northwest Energy Coalition in Case No. IPC-E-03-13. I am currently a member of Idaho

Power's Integrated Resource Plan Advisory Council.

Q. On whose behalf are you testifying?

A. I am testifying for Idaho Power Company (hereafter either "Idaho Power" or "the Company").

Q. Are you being compensated for this testimony by the Company, or have you or NRDC ever received any compensation or financial contributions from the Company?

A. No, unless you count travel reimbursement for meetings of the Company's Integrated Resource Plan Advisory Council.

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

A. My testimony supports the Company's proposals to (1) remove significant financial disincentives to sustained investments in cost-effective energy efficiency and small-scale "distributed" generating resources and (2) establish a pilot test of performance-based incentives for the Company's energy efficiency programs.

Q. What materials have you reviewed in preparation for this testimony?

A. I have reviewed the testimony of Mr. Youngblood and Mr. Gale in this proceeding. My testimony also owes much to the workshops convened by this Commission following the last Idaho Power Company rate case, at which I testified on behalf of the Northwest Energy Coalition. The report submitted on behalf of the groups that participated in those workshops is cited repeatedly in the testimony that follows. The Final Report on Workshop Proceedings, Case No. IPC-E-04-15 (February 14, 2005) is Exhibit No. 1.

Q. Summarize your conclusions and recommendations.

A. In May 2004, the Idaho Public Utilities Commission ("IPUC" or "Commission") opened a proceeding to address financial disincentives for Idaho Power's energy efficiency investments and performance-based incentives tied to the utility's success in delivering cost-effective savings. Please refer to pages 68 and 69 of IPUC Order No. 29505, Case No. IPC-E-03-13. Subsequent workshops yielded a report to the Commission, embraced by all participants, which included the conclusions that "the workshop participants agreed that material financial disincentives to the implementation of DSM programs do exist," (Exhibit No. 1, page 6) and called for detailed retrospective and prospective financial analyses to "evaluate incorporation of a true-up mechanism into the [Company's next] rate filing," (Exhibit No. 1, pages 10 and 11) along with pilot testing of a performance-based DSM incentive.

This testimony supports the Company's effort to sustain the progress that the Commission set in motion with its May 2004 order.

One of the Company's most important responsibilities involves integrated resource planning: assembling a diversified mix of demand- and supply-side resources designed to minimize the societal costs of reliable electricity supplies.[1] The Company is effectively a resource portfolio manager for its customers and, in the volatile financial markets of the early twenty-first century, the stakes and challenges have never been more daunting. Yet the regulatory status quo undercuts sound portfolio management by penalizing utility shareholders for reductions in electricity throughput over the distribution system, regardless of the cost-effectiveness of any contributing energy-efficiency, distributed-generation or fuel substitution measures.[2] From a customer's perspective, increases in throughput (above those contemplated when rates were established) result inappropriately in an over-recovery of fixed costs by the utility. And from an integrated resource planning perspective, a grave if unintended pathology of current ratemaking practice is the linkage of utilities' financial health to retail electricity throughput. Increased retail electricity sales produce higher fixed cost recovery and reduced sales have the opposite effect.

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[1] See, e.g., Idaho Power, 2004 Integrated Resource Plan (August 2004).

[2] This by no means exhausts the barriers to cost-effective resource portfolio management, and I hope for future opportunities to work with the Commission and interested parties on the full range of issues. One example is the way that the regulatory status quo penalizes shareholders for buying electricity from independent providers as opposed to owning generation, since there is a prospect of returns on investment only for owned (and rate-based) resources.

To address all of these problems, I support the Company's proposal that the Commission adopt a simple system of periodic true-ups in electric rates, designed to correct for disparities between the Company's actual fixed cost recoveries and the revenue requirement approved by the Commission in a general rate case proceeding. The true-ups would either restore to the Company or give back to customers the dollars that were under- or over-recovered as a result of annual throughput fluctuations. I also support the recommendation that the Commission approve a robust pilot test of performance-based incentives reflecting the Company's independently verified success in delivering cost-effective savings to its customers.

Q. What is the basis for your conclusion that Idaho Power's fixed cost recovery is strongly tied to its retail sales volumes?

A. Like most utilities, Idaho Power recovers most of its fixed costs through the rates it charges per kilowatt hour ("kWh"). In other words, a part of the cost of every kWh represents the system's fixed charges for existing plant and equipment; the rest collects the variable cost of producing that kilowatt-hour. After approving a fixed-cost revenue requirement, the IPUC sets rates based on assumptions about annual kilowatt-hour sales. If sales lag below those assumptions, the Company will not recover its approved fixed-cost revenue requirement. By contrast, if the Company were successful in promoting consumption increases above regulators' expectations, its shareholders would earn a windfall in the form of cost recovery that exceeded the approved revenue requirement. Whether consumption ends up above or below regulators' expectations, every reduction in sales from efficiency improvements yields a corresponding reduction in cost recovery, to the detriment of shareholders.

Q. Describe the evidence that market failures continue to block highly cost-effective energy savings at today's electricity prices.

A. Overwhelming evidence has been marshaled in recent years by the National Research Council of the National Academy of Sciences, the U.S. Congress's Office of Technology Assessment, the National Association of Regulatory Utility Commissioners, and the national laboratories, among many others. Although "[t]he efficiency of practically every end use of energy can be improved relatively inexpensively,"[3] "customers are generally not motivated to undertake investments in end-use efficiency unless the payback time is very short, six months to three years. The phenomenon is not

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[3] U.S. National Academy of Sciences Committee on Science, Engineering and Public Policy, Policy Implications of Greenhouse Warming, p. 74 (1991). A more recent review of energy-efficiency opportunities and barriers appears in National Research Council, Energy Research at DOE: Was it Worth It? (September 2001).

only independent of the customer sector, but also is found irrespective of the particular end uses and technologies involved."[4] Customers typically are demanding rates of return of 40-100+ percent, and such expectations differ sharply from those of investors in electric generation. Utilities' returns on capital average 12 percent or less. The imbalance between the perspectives of consumers and utilities invite large, relatively low-return investments in generation that could be displaced with more lucrative energy efficiency. These widely documented market failures generate "systematic underinvestment in energy efficiency," resulting in electricity consumption at least 20-40 percent higher than cost-minimizing levels.[5]

There are many explanations for the almost universal reluctance to make long-term energy efficiency investments.[6] Decisions about efficiency levels often are made by people who will not be paying the electricity bills, such as landlords or developers of commercial office space. Many buildings are occupied for their entire lives by very temporary owners or renters, each unwilling to make long-term

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[4] National Association of Regulatory Utility Commissioners, Least Cost Utility Planning Handbook, Vol. II, p. II-9 (December 1988).

[5] See M. Levine, J. Koomey, J. McMahon, A. Sanstad & E. Hirst, Energy Efficiency Policy and Market Failures, 20 Annual Review of Energy and the Environment 535, 536 & 547 (1995).

[6] An extensive assessment appears in U.S. Congress, Office of Technology Assessment, Building Energy Efficiency, at pp. 73-85 (1992).

improvements that would mostly reward subsequent users. Sometimes what looks like apathy about efficiency merely reflects inadequate information or time to evaluate it, as everyone knows who has rushed to replace a broken water heater, furnace or refrigerator.

Market failures like these mean that energy prices alone are a grossly insufficient incentive to exploit a continental pool of inexpensive savings: "a 2-year payback customer paying average rates of 7 cents/kWh can be expected to forego demand-side measures with costs of conserved energy of more than 0.9 cents/kWh."[7] That is, energy prices would have to increase about eightfold to overcome the gap that typically emerges in practice between the perspectives of investors in energy efficiency and production, respectively.

Q. Are you advocating punitively high electricity rates as a solution to these market failures?

A. Certainly not. Instead, I urge increased reliance on the very solution that the Commission and the Company have endorsed through Idaho Power's use of integrated resource planning: pursuit of cost-effective energy efficiency through utility investments rather than punitive prices.

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[7] National Association of Regulatory Utility Commissioners, note 4 above, p. II-10.

Q. What would happen to the Company's prospects for recovering authorized fixed costs if it were to exploit the huge potential for cost-effective electricity savings?

A. Although the societal and customer benefits would be significant, including avoided pollution and savings in both generation purchases and grid infrastructure investment, every additional unsold kilowatt-hour would reduce the Company's fixed cost recovery and undercut shareholder welfare, unless the Commission changed current ratemaking policies. Until this problem is solved, Idaho Power will lag in both aspirations and achievements on the demand side.

Q. How substantial are potential shareholder losses from reduced kilowatt-hour sales?

A. The Company's proposed fixed cost revenue requirement for the five major customer groups (see Youngblood Exhibit No. 7) is $303 million, of which $270 million would be recovered from variable demand and energy charges; energy charges alone would account for $212 million. Every one percent reduction in electricity use and demand on the Company's system would cut fixed cost recovery by about $2.7 million; every one percent increase would have the opposite effect. Since many efficiency measures last ten years or more, these one-year impacts must be multiplied at least tenfold when assessing shareholder interests.

But the losses get even worse in the context of multi-year programs initiated under a long-term resource plan. Consider a five-year program that pursues annual savings equivalent to one percent of system load, with each year adding new savings equivalent to the savings achieved during the previous year, and all savings persisting for at least five years. The first year's impact on fixed cost recovery is then about 2.7 million dollars, followed by 5.4 million dollars in the second year (as an equal amount of savings is added), and so on: the automatic five-year loss to shareholders from this steady-state utility investment program would be more than forty million dollars, with shareholder losses continuing to escalate in succeeding years as initial electricity savings persisted (with some gradual erosion) and more savings were added. Note that the shareholders would be absorbing these losses even as society gained from substituting less costly energy efficiency for more costly generation.

Q. What makes you think utilities can sustain cost-effective energy efficiency programs equivalent to about one percent of system consumption?

A. Recent history in Wisconsin and California proves as much.[8] In 1993, as reported by the Public Service

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[8] This reflects the most recent reported annual statewide savings (220,277 MWh for 2003 and 239,257 MWh for 2004). See

Commission of Wisconsin itself, statewide savings reached 621 gigawatt-hours, or about 1.2 percent of statewide electricity use.[9] The California Public Utilities Commission recently adopted comparable electricity savings targets for California's utilities. These targets represent 1.08 percent of system load in 2007 for the state's three principal utilities, ramping up to 1.13 percent in 2013.[10] By comparison, for 2004 and 2005, annual savings targets represented about 0.85 percent of those utilities' system loads.[11] Moreover, given previous levels of energy efficiency investment in the two states and comparative electricity prices, I would expect Idaho Power to have untapped energy efficiency opportunities at least equal to Wisconsin's and California's, in relative terms.

Q. Would cost-effective distributed generation programs have the same kind of adverse effect on Company earnings?

Wisconsin Public Benefits Program, <u>Annual Report, July 1, 2003 to June 30, 2004</u>, pp. 7.

[9] PSC-reported savings are from Wisconsin's Environmental Decade Institute, <u>Energy Efficiency Crisis Report</u>, p. 1 (1999); statewide electricity consumption data for 1993 are from State of Wisconsin, Department of Administration, <u>Wisconsin Energy Statistics 2004</u>, p. 46.

[10] See California Public Utilities Commission, Decision No. 04-09-060 (September 23, 2004).

[11] The annual energy savings for the 04-05 programs are from California Public Utilities Commission, D.03-12-062 (2003); the demand forecast for 2004-05 is from CEC, <u>California Energy Demand 2003-2013 Forecast</u> (Publication #100-03-002: 2003), Appendix A.

A. Yes. Adding distributed generation on the customer's side of the meter reduces retail kilowatt-hour sales and has adverse effects on fixed-cost recovery that are identical (per kWh of lost retail sales) to those described above.

Q. Why not just calculate the lost fixed-cost recovery associated with cost-effective energy efficiency programs and restore the funds to the utility?

A. This should not be done for at least three reasons. First, the calculations themselves would be hugely contentious and the rate impacts potentially significant, since each year's savings and lost revenues would persist over decades, with very significant financial consequences for all involved (recall that almost half of the retail value of kilowatt-hours represent "lost revenues" for this purpose). Second, the system would create additional perverse incentives for utilities, since the most lucrative programs would be those that looked good on paper while saving little or nothing in practice (allowing double recovery of "lost revenues"). Finally, the system would be inherently inequitable and asymmetrical, since the utility would be recovering its "lost revenues" from energy efficiency gains without being required to give up its "found revenues" from growth in sales associated with economic expansion elsewhere on the system.

These and related considerations figure strongly in a recent report by independent auditors to the Oregon Public Utility Commission, which evaluated the state's most recent experience with true-up mechanisms and recommended them as clearly superior to lost revenue adjustments, noting also that "with only lost revenue adjustments, the utility is discouraged from backing more general conservation efforts, such as pleas from the Governor to reduce consumption during an energy crisis, or proposals to improve energy efficiency standards embedded in building codes."[12]

Q. How would you propose to remove the financial disincentives described in earlier sections of your testimony?

A. To begin with, I support the joint recommendation of the Natural Resources Defense Council and the Edison Electric Institute to the National Association of Regulatory Utility Commissioners in November 2003: "To eliminate a powerful disincentive for energy efficiency and distributed-resource investment, we both support the use of modest, regular true-ups in rates to ensure that any fixed costs recovered in kilowatt-hour charges are not held hostage to sales volumes" (Exhibit No. 2). The state regulatory community has more than two decades of experience with such mechanisms, which involve a simple comparison of actual sales

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[12] D. Hansen & S. Braithwait, A Review of Distribution Margin Normalization as Approved by the Oregon Public Utilities Commission for Northwest Natural (March 2005), pp. 67-68.

to predicted sales, followed by an equally simple determination of actual versus authorized fixed cost recovery during the period under review. The difference is then either refunded to customers or restored to the Company, as the case may be. Note that the true-up can go in either direction, depending on whether actual retail sales are above or below regulators' initial expectations.

Q. Would the true-ups introduce significant new volatility in electricity rates?

A. No, because consumption does not fluctuate enough from year to year to require disruptive true-ups. Even aggressive conservation programs will not reduce loads by more than about one percent per year, as discussed above, and even under the extraordinary conditions prevailing in some recent years, Idaho Power's total retail electricity sales never dropped by more than 2.3 percent (Exhibit No. 3); indeed, since 1984, there was only one year (2002) in which systemwide retail sales did not increase. My assessment of recent trends in Idaho Power's system sales indicates that the largest plausible annual impact of a true-up mechanism would be less than two percent of retail rates or less than 1.5 mills - one and one-half tenths of a cent - per kilowatt-hour). By contrast, the Company's Power Cost Adjustment has increased rates by as much as 12 mills per kWh in recent years (with five rate increases of two mills or more since May 1998)

(Exhibit No. 4). The need for rate adjustments can be reduced further by integrating cost-effective energy efficiency targets into the forecasts developed for purposes of setting retail rates.

Q. Explain your conclusion about the plausible rate impact limits of a true-up mechanism.

A. A true-up mechanism would give back or restore the difference between authorized fixed cost recovery and actual recovery based on actual sales. Assuming that the Commission approves the Company's requested fixed cost revenue requirement of $303 million for the five major customer classes (Exhibit No. 7), and assuming that current fixed charges are not increased, about $270 million annually must be recovered from energy and demand charges. This means that about $2.7 million would be lost or gained for every one percent by which sales diverged from assumptions used to set rates.

Under these assumptions, a "worst case" annual rate impact of a true-up mechanism would come in a year comparable to 2002, when retail sales dropped by about two percent at a time when the Company was just beginning to ramp up energy efficiency programs. Assuming that such impacts were added to those of robust efficiency programs with savings equivalent to one percent of system-wide consumption, the true-up mechanism would still only have to restore about eight million dollars to compensate for a three percent reduction in consumption and associated fixed cost recovery. With total system revenues of $572 million (assuming that the Company's request is granted), this implies a system average rate increase of about 1.5 percent for the true-up under worst-case conditions. Under more typical circumstances in which consumption increases outpaced efficiency impacts, of course, the true-up could easily result in a modest rate reduction. Since 1993, electricity use on the Idaho Power system has increased by an average of about two percent annually (Exhibit No. 3). As shown in the illustrative calculation above, rate impacts up or down under a true-up mechanism would necessarily be modest as long as corrections occur on a regular basis and balances do not accumulate over multiple years.

These conclusions draw further support from the simulation exercise that Idaho Power conducted at the request of the workshop participants. The Idaho Power report, described in detail in Mr. Youngblood's testimony, indicates that the Company's proposed true-up mechanism would have resulted in extremely modest annual rate adjustments for each customer class over the past decade under reasonable assumptions about energy efficiency progress, with adjustments moving in both directions over the years for each class, as predicted above. Typical impacts for residential and small commercial customers would have been on the order of a dollar per month in bill reductions or increases, and even less in many of the years covered by the simulation. The Company concludes, and I agree, that the proposed mechanism can accommodate a three percent cap on annual rate impacts to any customer class without creating a risk of accumulating significant unrecovered or unrefunded balances over time.

Q. Wouldn't the proposed mechanism guarantee Idaho Power profits and reduce its incentives to minimize costs and pursue operating efficiencies?

A. No. The Company's incentives to minimize costs are not affected by this mechanism since, with or without the true-up, the Company keeps any operating savings that it achieves between rate cases and absorbs any overruns. The true-up guarantees only recovery of an authorized revenue requirement, not any particular level of earnings.

Q. What about the Company's incentive to provide good customer service?

A. The current linkage of utilities' financial health to retail energy use is itself antithetical to good customer service. Given Idaho Power's multitude of untapped cost-effective energy efficiency opportunities, giving utilities an incentive to promote increased electricity and gas use undermines key elements of good customer service; removing such an incentive is clearly a step in the right direction. But I also join the Company in recommending, as explained below, that the Commission supplement the true-up mechanism with a pilot test of performance-based rewards and penalties tied to the Company's success in helping customers improve energy efficiency and avoid more costly generation purchases.

Q. Is there relevant recent experience in neighboring states?

A. The most extensive recent activity with which I am familiar is in California, Oregon, Washington, and Wisconsin. California has embraced a true-up policy for all its investor-owned utilities, covering fixed costs of delivering both electricity and natural gas;[13] in California today, utilities' recovery of fixed costs is completely independent of retail sales. Not coincidentally, California utilities are conducting the nation's most aggressive energy efficiency programs (measured in savings as a percentage of retail electricity and natural gas use).

Oregon's PUC adopted a true-up mechanism for PacifiCorp in 1998, covering fixed costs of electricity

[13] In 2001, the California legislature enacted Public Utilities Code section 739.10, directing the PUC to "ensure that errors in estimates of demand elasticity or sales do not result in material over- or under-collections." The PUC has responded by reestablishing true-up mechanisms covering retail sales of both electricity and natural gas.

distribution.[14] Initial rate impacts of the Oregon "Alternative Form of Regulation" were extremely modest for all classes, and (as predicted) adjustments went in both directions; the largest annual rate increase for any class was 1.9 percent, the largest annual rate reduction was 0.83 percent and, out of a total of fifteen true-ups from 1999 - 2001, seven resulted in rate reductions and eight resulted in rate increases. More recently (in 2002), the Oregon PUC also adopted a modified true-up mechanism for Northwest Natural Gas; an independent evaluation concluded in March 2005 that the mechanism was "effective in altering Northwest Natural's incentives to promote energy efficiency" and should be retained, although the authors recommended removing some rather complex features that were not relevant to the mechanism's primary purpose.[15] The Oregon Commission adopted an order in August 2005 adopting a stipulation that simplified the mechanism and extended it for another four years.[16]

The Wisconsin Public Service Commission determined in July 2005 that utilities' financial disincentives were inappropriately constraining statewide energy efficiency development, and that "the time is right to

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[14] Oregon PUC, Order No. 98-191 (May 5, 1998) (covering 1998 - 2001). Rate impact data were supplied to me by PacifiCorp's Paul Wrigley.

[15] D. Hansen & S. Braithwait, A Review of Distribution Margin Normalization as Approved by the Oregon Public Utilities Commission for Northwest Natural (March 2005), pp. 67-68.

[16] Oregon PUC, Order No. 05-934 (UG 163, August 25, 2005).

fully explore true-up mechanisms and performance-based incentives."[17] Those efforts are now underway as Alliant, one of the state's principal utilities, convenes multi-party workshops to seek consensus on proposals to present to the Wisconsin Commission as part of Alliant's next rate case.

The Washington Utilities and Transportation Commission adopted a true-up mechanism for Puget Power in 1991. The mechanism guaranteed the Company recovery of an authorized level of fixed-cost "revenue per customer" prior to its next rate case. As the Commission determined at that time:

> [T]he revenue per customer mechanism does not insulate the Company from fluctuations in economic conditions, because a robust economy would create additional customers and hence, additional revenue. Furthermore, the Commission believes that a mechanism that attempts to identify and correct only for sales reductions associated with Company-sponsored conservation programs may be unduly difficult to implement and monitor. The Company would have an incentive to artificially inflate estimates of sales

[17] Public Service Commission of Wisconsin, Order No. 6680-UR-114, p. 55 (July 2005).

reductions while actually achieving little conservation.[18]

The Commission implemented Puget's revenue-per-customer cap by "set[ting] up a deferred account allowing a reconciliation of revenue and expenses that would be subject to hearing and review."[19]

Q. But didn't the Washington Commission subsequently repudiate this revenue-per-customer mechanism?

A. No, and I can underscore that response based on my own involvement throughout the process. In its initial review of the mechanism that it had adopted two years earlier, the Commission in 1993 "accept[ed] the parties' representations" that the revenue-per-customer system had "achieved its primary goal - the removal of disincentives to conservation investment," and concluded that "Puget has developed a distinguished reputation because of its conservation programs and is now considered a national leader in this area."[20] Based on these findings, the Commission granted a three-year extension of the revenue-per-customer

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[18] Docket No. UE-901183-T, Third Supplemental Order (April 10, 1991), p. 10. The Commission also determined that the mechanism did not constitute retroactive ratemaking, and that it was "fair, just and reasonable" even though it did not perfectly match costs and rates: "even under the current system of ratemaking, costs and rates will diverge immediately following implementation of a rate change." Id., at p. 10.
[19] Id., at p. 10.
[20] See Washington UTC, Eleventh Supplemental Order, Docket No. UE-920433, p. 10 (September 21, 1993).

mechanism.[21] In 1995, as part of a litigation settlement proposal intended to create no precedent, Puget and several other parties filed a request with the Commission to terminate a complex package of rate adjustment mechanisms that included the revenue-per-customer mechanism (along with a controversial approach to allocating risks of hydropower fluctuations). The Commission approved that request, but the proposal itself expressly reserved the right of all parties to bring forward in the future "other rate adjustment mechanisms, including decoupling mechanisms, lost revenue calculations, [and] similar methods for removing or reducing utility disincentives to acquire conservation resources."[22] In 2004, the Washington Commission invited the state's utilities and other stakeholders to reopen consideration of a true-up mechanism, in its order approving a settlement proposal by NRDC, the Commission staff, and PacifiCorp.[23] On December 7, 2005, NRDC and PacifiCorp filed a joint proposal to create such a mechanism, and the matter is now pending before the Commission.

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[21] Id., p. 10 (concluding that "the PRAM/decoupling experiment should continue for at least another three-year cycle").
[22] Docket No. UE-921262, Joint Report and Proposal Regarding Termination of the Periodic Rate Adjustment Mechanism (April 20, 1995).
[23] See Washington UTC v. PacifiCorp, Docket No. UE-032065, Order No. 06, pp. 29-30 (October 2004) (inviting PacifiCorp, following discussion with other parties, to "propose a true-up mechanism, or some other approach to reducing or eliminating any financial disincentives to DSM investment").

Q. Why don't more states have true-up mechanisms in place to eliminate disincentives for utility investment in demand-side resources?

A. A strong trend in that direction was interrupted in the mid-1990s by a stampede toward an industry restructuring model (pioneered in California) that denied utilities any substantial role in resource planning or investment. On that theory, there was no reason to worry about utilities' energy efficiency incentives, because utilities would be transferring their resource management responsibilities to unregulated participants in wholesale and retail electricity markets. The Western electricity crisis of 2000-2001 has discredited that model, which in any case never took hold in Idaho. Most states are now restoring full or at least significant utility responsibility for resource portfolio management, and interest in true-up mechanisms is reviving, as illustrated by Exhibit No. 2.[24]

Q. Is a true-up mechanism sufficient incentive to ensure that utilities invest aggressively in cost effective energy efficiency opportunities?

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[24] See also National Commission on Energy Policy, Reviving the Electricity Sector (Fall 2003), p. 3: "Regulated distribution companies can be compensated independently of increased electricity sales (for example, utilities' fixed-cost recovery can be made independent of retail electricity use, through the mechanism of small periodic upward or downward adjustments in distribution rates)."

A. I would describe it as necessary but not sufficient, over the long term, because the true-up removes a disincentive to investment but does not create an earnings opportunity. Such an opportunity is needed for its own conservation programs, in order to avoid an inherent bias toward generation and grid investments that can earn returns for shareholders. I recommend basing the incentive on verified performance rather than total dollars expended.

Q. What type of earnings opportunity would you recommend?

A. I recommend a performance-based incentive system tied directly to independent verification of savings and net benefits delivered by the Company's programs.[25] For performance exceeding a threshold specified by the Commission, in terms of verified savings and net benefits to customers from its programs, the Company should be allowed to keep a fraction of those net benefits at least comparable to the risk-adjusted reward on an equivalent investment in generation or grid assets; exemplary performance should qualify for higher rewards, subject to assurance that, in all cases, utility customers are clearly collective beneficiaries based on their retained share of system-wide dollar savings.

[25] The longstanding Wisconsin tradition of independent verification of program savings is reaffirmed in the Report of the Governor's Task Force, note 6 above, at p. 22 (discussing "independent third-party measurement and evaluation requirements").

Conversely, performance that failed to meet a threshold specified by the Commission should result in a penalty calculated by reference to net system benefits foregone.

Q. Are there precedents for performance-based incentives of this kind for utility investments in energy efficiency?

A. California instituted such incentives more than a decade ago as part of an effort to revitalize energy efficiency investment. The program received a strongly positive evaluation from independent auditors,[26] which included the following findings:

> Shareholder incentives are necessary to achieve a sustained level of aggressive DSM activity, and to ensure enthusiasm and commitment to quality rather than compliance behavior. They are necessary to diminish the gap between the private value of DSM to a utility (without the opportunity to earn) and DSM's societal value, so that DSM is implemented appropriately. By increasing the value of DSM to a utility, DSM benefits

[26] Wisconsin Energy Conservation Corporation, Final Report: Evaluation of DSM Shareholder Incentive Mechanisms (Prepared for the California Public Utilities Commission: January 1993).

that would otherwise not be captured will be attained.[27]

California is now in the process of reinstituting performance-based incentives as part of its effort to accelerate energy efficiency progress, as described earlier. The Wisconsin Public Service Commission strongly signaled its interest in creating such incentives in the most recent Alliant rate case (July 2005).[28]

Q. How would you resolve the questions that you posed regarding the design of a true-up mechanism, and what specific true-up mechanism do you recommend that the Commission adopt in this proceeding?

A. In testimony submitted in the Company's last rate case, I encouraged the Commission to "provide a reasonable period (three to six months) for the Company and interested parties to seek as much consensus as possible on design recommendations for the Commission's consideration." I predicted that if the Commission resolves the fundamental policy question, the Company and other interested parties will be able either to identify a preferred solution with wide support or, at minimum, to narrow and frame the issues in ways

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[27] Id., p. E-5.
[28] See note 25 above and accompanying text.

that will help the Commission achieve a swift and sound resolution."[29]

The workshops that the Commission convened certainly met those expectations, although they did not result in unanimous agreement on a preferred solution. Based in part on the workshop deliberations and record, I support the Company's recommendations, which reflect the final proposal that was developed over the course of the workshops submitted and summarized in the parties' report to the Commission (Exhibit No. 1, page 8).

Q. What criteria did you apply in reaching this conclusion?

A. In addition to the other considerations reviewed earlier in this testimony, I specifically applied the criteria developed and approved unanimously by the participants in the Commission's workshops on these very issues:

1. Stakeholders are better off than they would be without the mechanism,
2. Cross-subsidies are minimized across customer classes,
3. Financial disincentives are removed,
4. The acquisition of all cost-effective DSM are optimized,

[29]. IPUC Case No. IPC-E-03-13.

5. Rate stability is promoted,

6. The mechanism is simple,

7. Administrative costs and impacts of the mechanism are known, manageable, and not subject to unexpected fluctuation,

8. Short and long term effects to customers and Company are monitored,

9. Perverse incentives are avoided, and

10. A close link between mechanism and desired DSM outcomes is established.

Q. How would you recommend that the Commission proceed in developing performance-based incentives, as described earlier in your testimony?

A. As noted earlier, in May 2004, the Commission opened a proceeding to address financial disincentives for Idaho Power's energy efficiency investments and performance-based incentives tied to the utility's success in delivering cost-effective savings. Subsequent workshops yielded a report to the Commission, embraced by all participants, which included the conclusions that "the workshop participants agreed that material financial disincentives to the implementation of DSM programs do exist," and called for pilot testing of a performance-based DSM incentive. Consistent with the Final Report on Workshop Proceedings, I support the approval of a robust pilot program to test the concept.

Q. Does this conclude your testimony?
A. Yes, it does.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-04-15

IDAHO POWER COMPANY

EXHIBIT NO. 1

RALPH CAVANAGH

Final Report on Workshop Proceedings

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Boise, Idaho 83702

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE INVESTIGATION OF FINANCIAL DISINCENTIVES TO INVESTMENT IN ENERGY EFFICIENCY BY IDAHO POWER COMPANY	CASE NO. IPC-E-04-15 FINAL REPORT ON WORKSHOP PROCEEDINGS

INTRODUCTION

This is a final report to the Idaho Public Utilities Commission on the workshop proceedings undertaken in the above-captioned matter. This Final Report is intended to provide the Commission with an overview of the workshops and the issues discussed, and the recommendations of the workshop participants. Attached hereto are summaries of all five (5) workshops, which provide substantially more detail.

The workshops were successful in that they included an open and well-informed discussion of the nature and extent of fixed-cost revenue losses caused by demand-side management (DSM) programs, and possible means to neutralize those losses or create other incentives for strong performance in DSM programs. The participants in the workshops came to

EXHIBIT NO. 1
CASE NO. IPC-E-04-15
R. CAVANAGH, IPC
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a general consensus that Idaho Power should apply to the Commission to undertake a performance-based incentive pilot to allow the Company to fully recover fixed-cost losses and to possibly acquire incentive benefits achieved by its two residential programs covering the new construction market segment. These two programs are: (1) ENERGY STAR® Homes Northwest, its residential new construction energy efficiency program, and (2) Rebate Advantage for New Manufactured Homes, its program directed at the manufactured housing market. In addition, it was the general consensus of the workshop participants that the potential impacts of a broader fixed cost true-up mechanism should be simulated until Idaho Power's next general rate case.

BACKGROUND

On May 25, 2004, the Idaho Public Utilities Commission (Commission) in Order No. 29505 (Idaho Power Company general rate case No. IPC-E-03-13) determined that a separate "proceeding to assess financial disincentives inherent in Company-sponsored conservation programs is appropriate and should proceed by informal workshops." The Commission's Order provided in relevant part as follows:

> The Commission specifically directs the parties (Idaho Power, NW Energy Coalition, Industrial Customers of Idaho Power (ICIP) and Commission Staff) to address possible revenue adjustment when annual energy consumption is both above and below normal. The parties should also consider how much adjustment is necessary to remove DSM investment disincentives and whether (and to what extent) performance-based incentives such as revenue sharing could or should be incorporated into the resolution of this issue. The Commission is interested in proposals that could provide Idaho Power the opportunity to share and retain benefits gained from efficiencies, especially… technologies… In short, the Commission believes opportunities exist for improvements in operating efficiency that would benefit the Company shareholders and its customers, and we encourage the parties to creatively consider the options for a performance-based mechanism to present to the Commission. *The parties to the agreement are directed to propose a workshop schedule and initiate a proceeding.* (emphasis added)

Order No. 29505 at pp. 68, 69.

As a follow up to the Commission's Order, the NW Energy Coalition on June 18, 2004 formally requested that a proceeding be initiated and that a workshop schedule be established. The Commission in Order No. 29558 established this docket to investigate financial disincentives that hinder Idaho Power's investment in cost-effective energy efficiency resources. The Commission stated that the scope of the investigation should be focused on true-up mechanisms and performance based ratemaking.

As directed by the Commission, the participating parties provided a written status report to the Commission on December 15, 2004 to update the Commission on the status of the investigative workshops.

PROCESS

The parties participated in five workshops to date: August 24, September 27, November 8, December 1, and December 13, 2004. These workshops included presentations by participants, group discussion, and sensing for areas of agreement and disagreement. Susan Hayman (North Country Resources) facilitated the workshops. Workshops were designed in cooperation with four designated workshop coordinators representing each of the four major interests at the table (Idaho Power Company, Idaho Public Utilities Commission Staff, Industrial Customers of Idaho Power, and Northwest Energy Coalition). Copies of all workshop summaries are provided as attachments to this Final Report.

PARTICIPANTS

The following people attended one or more workshops, received meeting materials and summaries, and were considered active workshop participants:

Name and Affiliation

IPUC Staff

Lynn Anderson
Randy Lobb
Terri Carlock
David Schunke
Scott Woodbury

Idaho Power

Ric Gale

Bart Kline
Maggie Brilz
Darlene Nemnich
Greg Said
Tim Tatum
Mike Youngblood

Name and Affiliation

Northwest Energy Coalition

Nancy Hirsh, NW Energy Coalition
Bill Eddie, Advocates for the West
Ralph Cavanagh, Natural Resources Defense Council

Industrial Customers of Idaho Power

Peter Richardson, Industrial Customers of Idaho Power
David Hawk, J.R. Simplot Co
Don Reading, Ben Johnson Associates

Other Interested Parties

Brad Purdy, Community Action Partnership Association of Idaho
Laura Nelson, IPUC Policy Strategist

NATURE AND EXTENT OF LOST FIXED COST REVENUES

The underlying problem addressed in the workshops was described in the Direct Testimony of Ralph Cavanagh submitted in case number IPC-E-03-13: Successful implementation of DSM programs generally results in fewer sales of kilowatt-hours and/or reductions in demand for energy than would occur without the programs. Because Idaho Power primarily recovers its fixed costs of service as a portion of kilowatt-hour sales and/or demand charges, many DSM programs result in reduced fixed-cost revenue recovery.

The workshops first focused on identifying the nature and extent of fixed-cost revenue recovery impacts associated with varying levels of DSM investment by Idaho Power. These impacts are highly dependent on the type, level and effectiveness of DSM programs. For the workshop proceedings, IPUC Staff analyzed expected fixed-cost revenue losses over a 9-year period (with 2 assumed intervening rates cases) under the level of DSM investment recommended in the Northwest Power and Conservation Council's Fifth Plan. The Fifth Plan's level of DSM investment is approximately equal to savings on the order of 0.5% per year (including Northwest Energy Efficiency Alliance efforts, fuel conversions, building codes, appliance standards, and other DSM for which utilities have limited, little, or no control). Under Staff's contention that except for 6-month regulatory lag any future fixed-cost revenue losses from installed efficiency measures are "zeroed out" after each assumed rate case, the 9-year total fixed-cost revenue loss is \$54.6 million. The present value of the \$54.6 million is about \$39 million, and the levelized loss is \$6 million per year.

IPUC Staff conducted a similar 9-year analysis under the level of DSM investment anticipated under Idaho Power's 2004 Integrated Resource Plan. The 2004 IRP DSM plan does not include efficiency gains achieved under regional efforts such as NEEA, code changes, or other advancements, but does include a substantial increase in utility-managed DSM programs. Again assuming that any future fixed-cost revenue losses from installed efficiency measures are "zeroed out" after each rate case, the Staff-quantified 9-year total fixed-cost revenue loss is \$3 million; the present value is about \$2 million; and the levelized value is about \$0.3 million per year. This \$0.3 million amount is illustrative of the Staff-calculated fixed-cost revenue losses expected under potential levels of DSM activity identified by Idaho Power's 2004 Integrated Resource Plan (IRP).

However, as the discussion of NWPCC's Fifth Plan partly demonstrates, the amount of fixed-cost revenue losses would be much higher if the calculation accounted for other energy efficiency advances undertaken outside of Idaho Power's programs and for persisting energy efficiency measures across rate cases. In the workshops, NRDC and NWEC contended these analyses understated potential losses from aggressive Idaho Power DSM programs. For example, Ralph Cavanagh of NRDC reviewed with the group the basis for the conclusion in his filed testimony that programs saving just one percent of system-wide electricity consumption annually would eliminate about $45 million in fixed-cost recovery within just five years. And NRDC/NWEC contended that even regular rate cases could not remove the continuing adverse effects of long-term electricity savings on the Company's balance sheet.

The amount of fixed-cost losses incurred under all of these scenarios varies by customer class due to the differing fixed costs of service for each class, and the amount of fixed costs recovered from energy and/or demand charges that vary with consumption. More than other classes, the fixed costs of serving the residential and small commercial customers are recovered through variable energy charges – and DSM programs for this class result in the largest fixed cost revenue losses. Moreover, in the residential class, energy usage per customer generally has been declining in recent years from a high mark of an average 14,474 kWh customer/year in 1991 to 12,635 kWh customer/year in 2003.

POTENTIAL MECHANSIMS TO ADDRESS LOST FIXED-COST REVENUES

In light of the expected loss of fixed-cost revenues from DSM programs described above, the workshop participants agreed that material financial disincentives to the implementation of DSM programs do exist. However, not all participants agreed that restoration of lost fixed-cost revenues – such as through an annual true-up mechanism – would directly result in additional or more effective investment in DSM programs by Idaho Power. The Commission's order initiating this matter identified possible solutions to address the disincentives to investment in DSM programs created due to lost fixed-cost revenues, including a true-up mechanism to restore lost fixed costs, as well as performance based mechanisms to allow Idaho Power Company to share some of the benefits of successful DSM programs.

The workshop participants came to agreement on a set of criteria to evaluate different approaches to address lost fixed-cost revenues incurred by the Company due to successful DSM programs, or to provide incentives for DSM programs. The criteria are:

1. Stakeholders are better off than they would be without the mechanism.
2. Minimize cross subsidies across customer classes.
3. Removes financial disincentives.
4. Optimizes the acquisition of all cost-effective DSM.
5. Promotes rate stability.
6. Simple mechanism.
7. Administrative costs and impacts of the mechanism are known, manageable, and not subject to unexpected fluctuation.
8. Monitors short and long term effects to customers and company.
9. Avoids perverse incentives.
10. Close link between mechanism and desired DSM outcomes.

These criteria generally governed the workshop participants' consideration of mechanisms to address the lost fixed-cost revenues issue. For example, so-called "lost revenue recovery" mechanisms limited to DSM savings can be criticized because they turn program evaluation into a high-stakes adversarial process, and because they create an incentive for a utility to fashion a program that "looks good on paper," but does not actually perform well.

Likewise, a mechanism that simply trues up a utility's recovery of its authorized fixed-cost revenue requirement may be easy to implement and monitor, but only removes the financial disincentive to DSM while other barriers may remain. For that reason, a true-up mechanism on its own may not drive a utility to acquire all cost-effective DSM available in its territory. In addition, a true-up mechanism may shift the current allocation of risks from changes in sales due to weather, economic shifts, or technological advances.

The workshop participants gave careful consideration to two mechanisms: a true-up mechanism to ensure that Idaho Power recovered no more or less than its authorized fixed-cost revenue requirement; and a pilot program to provide an incentive to the Company to achieve substantial cost-effective savings in one important category of DSM programs.

True-up mechanism: The Natural Resources Defense Council and NW Energy Coalition proposed a true-up mechanism to restore lost fixed-cost revenues to Idaho Power. The starting point for the proposal was the fixed-cost revenue requirement and retail rates approved by the Commission for Idaho Power's most recent rate case. The fixed-cost revenue requirement would then be automatically adjusted annually (until reestablished in the next rate case) as follows: (a) for the Industrial and Agricultural sectors, the fixed cost revenue requirement would be adjusted to reflect the same rate of increase (or decrease) shown for retail electricity sales, net of any DSM programs, in the load forecast section of Idaho Power's latest Integrated Resource Plan; or (b) for the Residential and Commercial sectors, the fixed cost revenue requirement would be adjusted to reflect the actual changes in annual customer count for the residential and commercial sectors (in other words, the fixed cost revenue requirement per customer would remain fixed until the next rate case). Concurrent with each annual power cost adjustment case, true ups would occur by customer class based on any divergence between the total fixed-cost revenue recovery that forecast sales of kilowatt-hours and demand charges (for Agricultural and Industrial sectors) or actual customer growth (for Residential and Commercial) would have delivered versus the fixed-cost revenues actually recovered through actual sales. Idaho Power would continue to absorb the risk or benefits of purely weather-related effects on fixed-cost revenue recovery, as it does now. Actual sales would be weather-normalized before making the annual true-up calculation. The maximum annual average rate impact of the true up mechanism for any customer class would be capped at 2% annually, with any additional amounts carried over to the next year's true up.

Rather than actual implementation, the workshop participants agreed to a "Simulation" of the true-up proposal to help illuminate its potential impacts under the criteria described above. The Simulation would include both retrospective and prospective components by using the fixed-cost revenue requirements approved in the 1994 and 2004 rate cases as starting points. It would apply an assumed level of efficiency savings of 0.5% annually (roughly equivalent to the level of savings achievable under the NWPCC's Fifth Plan) each year starting in 1994 and 2004.

To illuminate the impacts of the true-up proposal, the Simulation would calculate the: (1) annual rate impact to each customer class for the true-up; (2) the impact of DSM savings on the PCA; (3) the annual impact to average customer bill amounts (assuming the 0.5% annual efficiency savings and the annual net benefit estimates developed in the energy efficiency assessment provided as an addendum to the 2004 IRP); and (4) total impact of true-up mechanism to IdaCorp shareholders.

Pilot Incentive: At the group's request the IPUC Staff developed a strawman proposal for a performance based Pilot Incentive. Staff chose to target the ENERGY STAR® Homes Northwest program for the strawman and at the group's request, Idaho Power and IPUC Staff later collaboratively refined it into a proposal. This DSM program, which was included in the Company's 2004 IRP, offers an incentive to builders to achieve a standard of 30% energy savings over and above existing code requirements. The original program proposal targeted a specific number of homes in which to achieve these savings in 2005. With further refinement, Idaho Power adopted a MWH reduction target, encouraging the company to achieve even greater savings as well as putting the focus of the program on energy savings rather than a specific number of homes. The energy target to be achieved through this program in 2005 is a reduction of 1,070 annual MWH. The Idaho Energy Division conducts quality assurance for the program, and NEEA provides builder training. Under the Pilot Incentive, Idaho Power would recover fixed-cost revenues lost due to the validated energy savings provided by the program, and earn an additional incentive if the energy savings achieved by the program exceed 100% of the targeted savings. As described below, Idaho Power is expected to submit an application to the Commission to implement this program.

The ENERGY STAR® Homes Northwest program was chosen for the Pilot Incentive, because residential rates have a high fixed-cost component recovered through variable energy charges and because it is a relatively small program so any potential unanticipated impacts of the Pilot Incentive will be small. Also, this program is projected to be very cost effective and its results are expected to be relatively easy to monitor. The workshop participants also agreed to recommend adding Idaho Power's Energy Efficient Manufactured Home Incentives program to the Pilot Incentive. The targeted savings for this project is 555 annual MWH.

RECOMMENDATIONS OF THE WORKSHOP PARTICIPANTS

Idaho Power Company anticipates filing an application with the Commission to implement the pilot program described above. The workshop participants are supportive of the pilot as described in the workshops, but reserve their rights to comment on the proposal as filed with the Commission.

In addition, Idaho Power has agreed to implement a Simulation of the true-up mechanism proposed by NRDC and NW Energy Coalition, as described above, until Idaho Power's next general rate case. This action does not require action by the Commission; however, the results of the Simulation will be provided to workshop participants and the Commission contemporaneously with each annual PCA filing. Idaho Power will work with workshop participants as the Company prepares its next rate case filing to analyze the results of the Simulation and evaluate incorporation of a true-up mechanism into the rate filing.

This Final Report to the Commission has been reviewed and approved by Commission Staff and Idaho Power Company.

Dated this 14th day of February, 2005. Respectfully submitted,

William Eddie
Attorney for NW Energy Coalition

CERTIFICATE OF SERVICE

I hereby certify that on this 14th day of February 2005, true and correct copies of the foregoing FINAL REPORT were delivered to the following persons via hand delivery (for Commission recipients) and U.S. Mail (for all others):

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE INVESTIGATION OF FINANCIAL DISINCENTIVES TO INVESTMENT IN ENERGY EFFICIENCY BY IDAHO POWER COMPANY	)	CASE NO. IPC-E-04-15 ATTACHMENTS TO FINAL REPORT ON WORKSHOP PROCEEDINGS

Attached hereto are summaries of all five (5) workshops conducted in the above matter. Due to the volume of material, one original printed copy is provided to the Commission, together with a computer disc providing electronic copies of the same. Additional computer discs can be obtained by contacting the undersigned counsel.

Dated: February 14, 2005

Respectfully submitted,

William M. Eddie
Attorney for NW Energy Coalition

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UTILITIES COMMISSION

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-04-15

IDAHO POWER COMPANY

EXHIBIT NO. 2

RALPH CAVANAGH

Joint Recommendation of the Natural Resources Defense Council and the Edison Electric Institute to the National Association of Regulatory Utility Commissioners

EDISON ELECTRIC INSTITUTE

NRDC
THE EARTH'S BEST DEFENSE

November 18, 2003

Dear NARUC Commissioners

At your invitation, we conducted a lively debate at the 2002 Annual Meeting on utilities' future role in "electric resource portfolio management." Many of you encouraged us to return with joint recommendations on the formidable challenges associated with choosing and managing balanced portfolios of electricity and grid resources for customers unable or unwilling to do this themselves. Here we are again.

While details vary among states, EEI and NRDC agree that among most distribution companies' most crucial and challenging responsibilities is meeting their systems' long-term needs for grid enhancement, generation and demand-side resources. Distribution companies need not own the resources involved, and an active portfolio management role for distribution companies is entirely consistent with efforts to promote competitive wholesale generation markets. Indeed, as NARUC's members know well, many participants in such markets increasingly are calling for more long-term distribution company investments to help overcome a capital availability crisis that affects all elements of the power system, from grids to generators to end-use efficiencies.

We are deeply concerned, however, about an increasingly obvious mismatch between these important societal needs and the tools available to utilities, other market participants and regulators. We also believe we need clear workable frameworks for resource portfolio procurement, and we are committed to working together with NARUC's members to secure them.

THE CHALLENGES

Utility-based resource portfolio management faces a host of challenges, including but not limited to the following:

1. Misaligned incentives.
   a. Traditional regulation does not create any clear performance-based incentive to manage comprehensive electric resource portfolios effectively; at best, utilities can hope to recover the costs of long-term contracts with generation and demand-side service providers, with no opportunity to earn a reward for addressing risks in minimizing the long-term cost of reliable service.
   b. For energy efficiency and distributed generation options specifically, today's rate regulation typically penalizes any such utility investments - however cost-

effective - by linking much or all of utilities' fixed cost recovery to their retail electricity sales volumes.

c. Traditional rates of return from a cost-of-service framework do not reflect significant new risks (outlined in part below).

d. It is difficult to negotiate symmetrical incentives that reward long-term performance and will not be revisited or withdrawn when utilities do well.

2. Major new risks in honoring service obligations in restructured markets:
   a. Volume Risk: in states with retail competition loads are far more variable because of customer switching; and,
   b. Price Risk: wholesale prices are increasingly volatile, most customers don't like being exposed to such volatility, and many utilities have divested their own generation in response to market forces and/or direction from regulators and legislatures.

3. Illiquidity in wholesale markets: lack of long-term deals impedes temporal diversity, and lack of derivative products obstructs some kinds of risk hedging.

4. Uncertainty regarding the duration of the supply obligation: some states have reframed portfolio management as "Provider Of Last Resort" (POLR) service, which was originally intended to be part of a transitional strategy but now is being recast as a renewed and extended obligation.

5. Analytical challenges in developing sound portfolios: portfolio managers must find new tools and methods to evaluate regulated and unregulated resources with significantly different asset lives and non-price attributes; Commissions need to gain greater familiarity with new risk management concepts, methods and tools (e.g., Value-at-Risk, Cash Flow-at-Risk, measures of gas price volatility)

6. Expediting decisions: traditional trial-type adversarial planning proceedings take too long to identify and exploit opportunities.

7. Addressing the role of affiliates: no consensus yet exists on whether and how to accommodate affiliate participation in resource portfolios.

NEXT STEPS

This daunting list of concerns is not an invitation to despair or for paralysis; solutions must be found in the public interest. We offer these initial recommendations and remain committed to timely solutions:

1. Get the incentives right: performance-based incentives tied to objective benchmarks have been tested for both demand- and supply-side resources; it's time to put them to widespread use. Procurement plans filed by utilities with their regulators can be used to establish these benchmarks, which should address cost-effective short- and long-

term investments in generation, demand-side resources and grid enhancements. Also, to eliminate a powerful disincentive for energy efficiency and distributed-resource investment, we both support the use of modest, regular true-ups in rates to ensure that any fixed costs recovered in kilowatt-hour charges are not held hostage to sales volumes. EEI believes regulators should explore new rate designs for collection of the fixed costs of investments.

2. Provide reasonable assurance of cost recovery: uncertainty of cost recovery constrains adaptive rate design, and discourages investment in new infrastructure needed for security, reliability and environmentally sustainable service for all customers. Moreover, extended rate freezes make impossible any true-ups to remove energy efficiency disincentives (see item 1 above).

3. Provide opportunities for utilities to seek advanced regulatory approval for resource portfolios under standards and criteria defined upfront, with assurances that approved commitments will not be revisited and disapproved after-the-fact.

4. Add objective risk management goals to the traditional utility resource procurement mission of minimizing costs subject to reliability and other constraints.

5. Establish frequent communications with Commissioners and staff, to keep up with dynamic market changes and avoid surprising regulators.

6. Develop RFP processes that are unbiased and fair for all parties, including utility affiliates and independent suppliers. One illustration is the joint NRDC/PacificCorp/Calpine proposal *Defining Electricity-Resource Portfolio Management Responsibilities* submitted to NARUC in July 2003.

Through these recommendations, we hope to help NARUC members achieve the best possible long-term results for all of their constituents, in both economic and environmental terms.

Yours sincerely,

David K. Owens
David K. Owens

Ralph Cavanagh
Ralph Cavanagh

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-04-15

IDAHO POWER COMPANY

EXHIBIT NO. 3

RALPH CAVANAGH

Idaho Power Company
Historical Customer and Energy Usage

Retail Sales

Year	Idaho Customers	Growth in Customer Count	Idaho MWH	Growth in Energy Usage	Difference	Avg Use/Cust kWh	Growth in Use/Cust
1972	168,242		3,999,528			23,772	
1973	176,849	5.1%	4,441,325	11.0%	5.9%	25,114	5.6%
1974	185,115	4.7%	4,863,173	9.5%	4.8%	26,271	4.6%
1975	193,671	4.6%	5,400,905	11.1%	6.4%	27,887	6.2%
1976	202,816	4.7%	5,791,354	7.2%	2.5%	28,555	2.4%
1977	212,629	4.8%	6,116,342	5.6%	0.8%	28,765	0.7%
1978	223,249	5.0%	6,396,271	4.6%	(0.4%)	28,651	(0.4%)
1979	231,736	3.8%	6,957,866	8.8%	5.0%	30,025	4.8%
1980	238,937	3.1%	7,014,445	0.8%	(2.3%)	29,357	(2.2%)
1981	243,830	2.0%	7,273,846	3.7%	1.7%	29,832	1.6%
1982	247,457	1.5%	7,222,908	(0.7%)	(2.2%)	29,189	(2.2%)
1983	250,902	1.4%	7,158,167	(0.9%)	(2.3%)	28,530	(2.3%)
1984	254,597	1.5%	7,175,798	0.2%	(1.2%)	28,185	(1.2%)
1985	257,991	1.3%	7,314,487	1.9%	0.6%	28,352	0.6%
1986	260,319	0.9%	7,374,735	0.8%	(0.1%)	28,330	(0.1%)
1987	262,717	0.9%	7,459,102	1.1%	0.2%	28,392	0.2%
1988	265,365	1.0%	7,737,505	3.7%	2.7%	29,158	2.7%
1989	269,256	1.5%	8,034,421	3.8%	2.4%	29,839	2.3%
1990	275,256	2.2%	8,367,307	4.1%	1.9%	30,398	1.9%
1991	281,360	2.2%	8,514,896	1.8%	(0.5%)	30,263	(0.4%)
1992	289,013	2.7%	8,695,622	2.1%	(0.6%)	30,087	(0.6%)
1993	298,411	3.3%	8,981,236	3.3%	0.0%	30,097	0.0%
1994	309,567	3.7%	9,262,924	3.1%	(0.6%)	29,922	(0.6%)
1995	320,032	3.4%	9,559,202	3.2%	(0.2%)	29,870	(0.2%)
1996	330,856	3.4%	9,790,919	2.4%	(1.0%)	29,593	(0.9%)
1997	340,989	3.1%	9,984,121	2.0%	(1.1%)	29,280	(1.1%)
1998	351,075	3.0%	10,356,330	3.7%	0.8%	29,499	0.7%
1999	361,479	3.0%	10,637,730	2.7%	(0.2%)	29,428	(0.2%)
2000	371,583	2.8%	10,997,104	3.4%	0.6%	29,595	0.6%
2001	381,421	2.6%	11,112,598	1.1%	(1.6%)	29,135	(1.6%)
2002	391,471	2.6%	10,853,895	(2.3%)	(5.0%)	27,726	(4.8%)
2003	401,942	2.7%	11,114,408	2.4%	(0.3%)	27,652	(0.3%)

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-04-15

IDAHO POWER COMPANY

EXHIBIT NO. 4

RALPH CAVANAGH

Historical PCA Rate Changes

PCA Rate Changes
PCA Cents per kWh Charges

Customer Class	05/16/98	05/16/99	05/16/00	05/01/01	Effective Date 10/01/01	05/16/02	07/01/02	05/16/03	06/01/04	06/01/05
Metered Schedules and Special Contracts										
PCA Rate per kWh	0.1598	(0.2143)	0.1371	1.3415	1.7241	1.9370	1.9370	0.6039	0.6039	0.6039
Difference from previous rate	0.3150	(0.3741)	0.3514	1.2044	0.3826	0.2129	0.0000	(1.3331)	0.0000	0.0000
NonMetered Schedules										
PCA Rate per kWh	0.1598	(0.2143)	0.1371	1.3415	1.7241	1.9370	1.9370	0.6039	0.6039	1.6039
Difference from previous rate	0.3150	(0.3741)	0.3514	1.2044	0.3826	0.2129	0.0000	(1.3331)	0.0000	1.0000
Schedules 24 and 25										
PCA Rate per kWh	0.1598	(0.2143)	0.1371	1.3415	1.7241	1.3415	1.3415	1.3159	0.5054	0.6052
Difference from previous rate	0.3150	(0.3741)	0.3514	1.2044	0.3826	(0.3826)	0.0000	(0.0256)	(0.8105)	0.0998
Schedule 7										
PCA Rate per kWh	0.1598	(0.2143)	0.1371	1.3415	1.7241	1.7241	1.7241	0.8477	0.5761	0.6039
Difference from previous rate	0.3150	(0.3741)	0.3514	1.2044	0.3826	0.0000	0.0000	(0.8764)	(0.2716)	0.0278
Schedule 19										
PCA Rate per kWh	0.1598	(0.2143)	0.1371	1.3415	1.7241	1.9370	1.7241	0.8217	0.5731	0.6039
Difference from previous rate	0.3150	(0.3741)	0.3514	1.2044	0.3826	0.2129	(0.2129)	(0.9024)	(0.2486)	0.0308
Schedule 1										
0-800 kWh				0.8049	1.2349					
801-2000 kWh				1.6098	2.0398					
2001-All Over kWh				3.4586	3.4586					
PCA Rate per kWh	0.1598	(0.2143)	0.1371	1.3415	1.7241	1.9370	1.9370	0.6039	0.6039	0.6045
Difference from previous rate	0.3150	(0.3741)	0.3514	1.2044	0.3826	0.2129	0.0000	(1.3331)	0.0000	0.0006

EXHIBIT NO. 4
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R. CAVANAGH, IPC
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