IDAHO POWER®
An IDACORP Company

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IDAHO PUBLIC UTILITIES COMMISSION

BARTON L. KLINE
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April 9, 2010

VIA HAND DELIVERY

Jean D. Jewell, Secretary
Idaho Public Utilities Commission
472 West Washington Street
P.O. Box 83720
Boise, Idaho 83720-0074

Re: Case No. IPC-E-09-28
CONVERT SCHEDULE 54 – FIXED COST ADJUSTMENT – FROM A PILOT SCHEDULE TO AN ONGOING, PERMANENT SCHEDULE

Dear Ms. Jewell:

Enclosed for filing please find an original and seven (7) copies of Idaho Power Company's Reply Comments in the above matter.

Very truly yours,

Barton L. Kline

BLK:csb
Enclosures

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO CONVERT SCHEDULE 54 – FIXED COST ADJUSTMENT – FROM A PILOT SCHEDULE TO AN ONGOING, PERMANENT SCHEDULE.	CASE NO. IPC-E-09-28 REPLY COMMENTS OF IDAHO POWER COMPANY

Idaho Power Company ("Idaho Power" or "Company") hereby replies to the comments filed by the Staff of the Idaho Public Utilities Commission ("Staff"), the Idaho Conservation League ("ICL"), Snake River Alliance ("SRA"), Community Action Partnership Association of Idaho ("CAPAI"), and AARP.

I. BACKGROUND

In Order No. 30267, issued on March 12, 2007, in Case No. IPC-E-04-15, the Commission approved a three-year pilot program under which the Company implemented a fixed cost adjustment ("FCA") mechanism for residential service (Schedules 1, 3, 4, and 5) and small general service (Schedule 7) customers. Idaho

Power's rates for those two customer classes have historically been designed to recover a significant portion of the Company's fixed costs in the energy price. When energy sales increase or decrease, fixed cost recovery also increases or decreases. The FCA provides a true-up mechanism that allows the Company to recover (or refund) the difference between the amount of fixed costs authorized for recovery by the Commission in the Company's most recent general rate case and the fixed costs that the Company actually recovered through energy related rate components during the previous year. The FCA is often referred to as a "decoupling" mechanism because it separates fixed cost recovery from energy sales volumes.

II. BENEFITS OF THE FCA

All of the parties that formally intervened in this case ("Intervenors") note in their Comments that they support the FCA and recognize the positive benefits customers obtain by implementation of the FCA.[1] The FCA's "true-up" mechanism benefits customers three ways. First, cost-effective energy efficiency and demand-side management (collectively "DSM") programs can lower customer costs. Customers benefit from the FCA true-up mechanism because the Company is not financially harmed by decreases in energy sales within the residential and small general service customer classes nor is it financially benefitted from increases in energy sales. Thus, the FCA removes a disincentive that would otherwise discourage the Company from pursuing additional DSM programs and expenditures. The implementation of the pilot FCA has facilitated significant increases in the Company's promotion and expenditures to pursue energy efficiency and demand-side management programs, which have resulted in significant energy efficiency savings.

[1] AARP did not intervene but filed comments opposing any extension of the FCA.

Demand-Side Management Activities

	New Investment	Annual Percent Increase	MWh Savings	Percent Increase	Total # of DSM Programs	Percent Increase
2006	$11,484,013		70,766		17	
2007	$15,662,378	36%	91,145	29%	18	6%
2008	$21,193,520	35%	140,156	54%	22	22%
2009	$34,846,766	64%	148,256	6%	24	9%

Source: *2006, 2007, 2008, 2009 Demand-Side Management Annual Reports*

As the above table shows, the Company has substantially increased the number of DSM programs and its level of expenditures for energy efficiency and demand response programs since the inception of the FCA pilot on January 1, 2007.

Second, the FCA true-up acts to stabilize customer bills when loads are increasing because the fixed cost component being recovered through the energy rate is less than the total energy rate. As a result, when average load per customer increases during a year, the average customer bill is less with the FCA than it would have been without the mechanism.

Third, customers benefit from the FCA when loads are decreasing because it gives the Company a better opportunity to recover more of the fixed costs it incurs to provide electric service to customers. Regulatory mechanisms that improve the Company's ability to recover its costs are perceived by the debt rating agencies and financial community as positive attributes and therefore the Company's cost of capital may be reduced. The Commission is aware that the Company will be making substantial additional investments in transmission, distribution, and generation infrastructure in the near term. Lower financing costs will help lower customer costs for funding these investments. The role of the FCA in improving credit ratings is not just speculation by the Company. Moody's Investor Service recently improved Idaho Power's credit rating from Baa1 negative to Baa1 stable. In its credit opinion describing the reasons for the upgrade, Moody's specifically identified the FCA as one of the positive attributes it considered in making its decision to upgrade the Company's credit rating. A copy of the pertinent portions of the Moody's credit opinion is enclosed as Attachment No. 1.

1. <u>The FCA Is Generally Recognized As a Beneficial Regulatory Mechanism</u>.

All the commentors, with the exception of AARP, indicate that they support the FCA and recognize the positive benefits customers obtain by implementation of the FCA. In addition to the Staff and Intervenors in this case, other entities in the state of Idaho have also acknowledged the benefits flowing from the FCA.

For example, in his March 19, 2009, letter to the United States Secretary of Energy, written in support of Idaho's effort to obtain stimulus funds, Governor Otter cited the fact that he "has requested that the Commission continue their successful decoupling efforts . . . ." as evidence that Idaho deserved a share of the $3.1 billion in federal funding for the state energy program ("SEP"). A copy of Governor Otter's March 19, 2009, letter is enclosed as Attachment No. 2.

Another instance where the FCA was cited positively was in the Commission and the Idaho Office of Energy Resource's ("OER's") December 11, 2009, Joint Report to the Legislature regarding the successful implementation of the 2007 Idaho Energy Plan ("Joint Report"). In the Joint Report, the OER and the Commission specifically identified the fact that the Commission had adopted one of the nation's first electric decoupling mechanisms designed to remove financial disincentives for Idaho Power Company to implement energy cost efficiency programs. In their Report, the OER and the Commission describe the FCA as a positive step to encourage Idaho Power to aggressively and cost-effectively pursue energy efficiency and DSM programs. On page 10 of the Joint Report, the OER and the Commission specifically point to the fact that shareholders are also an important stakeholder in the Company's efforts to aggressively pursue DSM programs. For the convenience of the Commission's review, a copy of the pertinent section of the Joint Report is enclosed as Attachment No. 3.

In Case No. GNR-E-08-04, the Commission fulfilled its obligation under the Energy Independence and Security Act of 2007 by considering policies that "remove the throughput incentive and regulatory and management disincentives to energy efficiency." (16 USC § 2621(17)(B)(i).) In that case, the Commission found that "it has or is presently considering energy efficiency programs such as fixed cost adjustments, tiered rates, time of use rates, seasonal rates, and decoupling" such that it has "already adopted comparable standards for rate design modifications to promote energy efficiency investments by utilities." (Order No. 30966 at p. 6.)

A copy of the pertinent portion of the above-referenced federal law is enclosed as Attachment No. 4.

Finally, as previously noted, the FCA is recognized by the financial community as a positive indication of proactive regulation. Various utility equity analysts have identified the FCA as a positive attribute in assessing whether or not to recommend that their customers buy Idaho Power's stock. Enclosed as Attachment No. 5 are copies of the pertinent portions of equity research reports from RBC Capital Markets, Wells Fargo Bank, and Key Banc. In these examples, the equity research firms identify the fact that

Idaho Power has a de-coupling mechanism in place in the state of Idaho as an indication of a positive regulatory environment in Idaho.

2. <u>The FCA Is Performing Exactly As Intended</u>.

During the workshops that led up to the submittal of the Stipulation which created the FCA, the workshop participants developed a list of criteria that any regulatory mechanism for decoupling utility energy sales from fixed cost recovery should meet. The criteria developed by the participants are as follows:

a. Stakeholders are better off than they would be without the mechanism. (Stakeholders include both customers and shareholders.)

b. Cross subsidies are minimized across customer classes.

c. Financial disincentives are removed.

d. The acquisition of all cost-effective DSM is optimized.

e. Rate stability is promoted.

f. The mechanism is simple.

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

h. Short-term and long-term effects to customers and Company are monitored.

i. Perverse incentives are avoided.

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

These criteria were presented to the Commission in the Final Report on workshop proceedings filed with the Commission on February 14, 2004. The criteria were subsequently noted by the Commission in Order No. 30267 when the Commission approved the FCA pilot program. (Order No. 30267 at p. 6.)

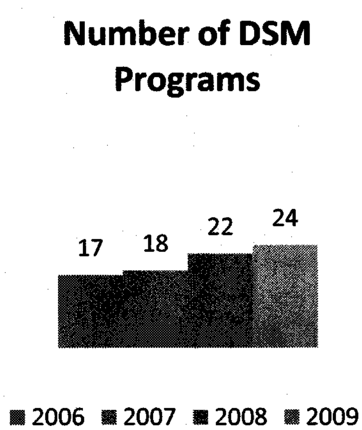
In comparing the above-described criteria to the actual operation of the FCA, it is clear that the current FCA mechanism meets all of the criteria established by the parties and presented to the Commission. As the Commission noted in Order No. 30267:

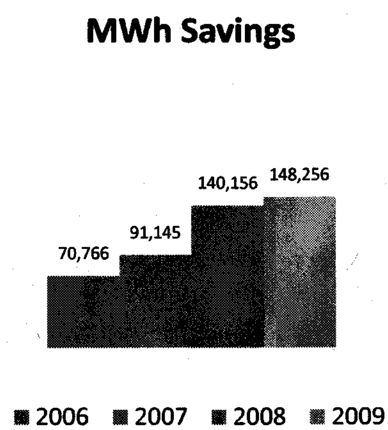
> Promotion of cost-effective energy efficiency and demand-side management (DSM), we find, it is an integral part of least-cost electric service. This case was opened to identify financial disincentives to Idaho Power's investment and energy efficiency. The Company proposed FCA mechanism removes a Company-identified financial disincentive to energy efficiency and DSM investment and is designed to reduce on a per customer basis the utility's dependence on revenue from stable kilowatt-hour sales. The FCA methodology is a departure from traditional ratemaking and merits a cautious approach to implementation. The annual FCA true-up mechanism assures a more stable utility recovery of fixed costs that are now recovered in the energy rate component of residential and small general service customers. (Order No. 30267 at p. 13.)

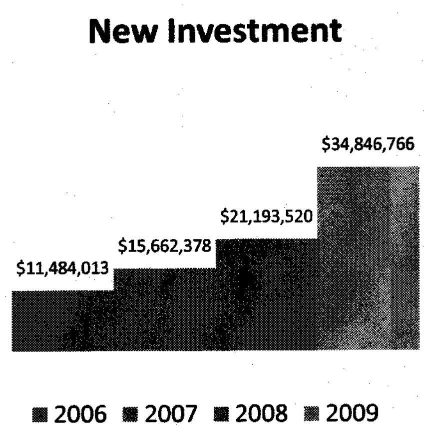
The Commission went on to say in Order No. 30267, "Making the Company indifferent to reduced energy consumption and demand is but one-half of the quid pro quo agreed to by the stipulating parties. In return for the FCA, the Company is expected to demonstrate an enhanced commitment to energy efficiency and DSM." (Order No. 30267 at pp. 13-14.)

The pre-filed testimony of Mr. Sparks provides verifiable evidence that the existing FCA meets both prongs of the test for demonstrating the effectiveness of the FCA the Commission described in Order No. 30267. First, the FCA provides a symmetrical (surcharge/credit) when fixed cost recovery per customers varies above or below a Commission-established base. As Mr. Sparks notes in his testimony on page 12, due to the operation of the FCA, customer rates were reduced in 2007 and increased in 2008. As a result, the Company has become indifferent to reduced energy consumption and demand from the participating customer classes. Idaho Power's recovery of fixed costs is more stable as are its customers' bills. This stabilizing effect has been noted by the financial community as a positive regulatory approach. (See Attachments Nos. 1 and 5.)

The second prong of the Commission's test of the efficacy of the FCA is whether or not the Company has complied with its commitment to increase its energy efficiency and DSM efforts. The evidence clearly demonstrates this is the case. Mr. Sparks' pre-filed testimony in this case provides a detailed description of the numerous new and expanded DSM and energy efficiency programs that the Company has initiated since the FCA was implemented. As the bar chart provided below shows, there is no doubt that removal of the acknowledged disincentive by the FCA has had the desired effect of stimulating the Company's DSM efforts.







3. **<u>Removal of the Disincentive to Promote Cost-Effective DSM Benefits Customers</u>.**

In its Comments, Staff acknowledges that customers benefit when the Company acquires DSM energy savings at costs that are lower than the alternative supply-side resources. (Staff Comments at p. 11.) As a practical matter, this disincentive extends to other load reducing activities as well, including customer education and information, support for revised building codes and standards, and pricing consistent with energy efficiency. Staff also acknowledges there is a financial disincentive for the Company to pursue cost-effective DSM when doing so reduces recovery of prudently incurred Commission-approved fixed costs. (Staff Comments at pp. 2 and 11.) While the Comments of the Staff and Intervenors all support continuation of the FCA, they also argue that the FCA should be continued as a pilot program rather than making it a permanent program as Idaho Power has requested. In support of their recommendation for continued pilot program status, ICL, Staff, and CAPAI all identify a number of questions and uncertainties that they claim have not been resolved during the term of the pilot program. For the most part, these are the same questions and uncertainties that were initially raised in Case No. IPC-E-04-15. For example, throughout the entire course of the workshops and negotiations that ultimately led to the Stipulation, one of the questions that was addressed at length was how can we be sure that an increased level of conservation activity by the Company is a direct result of the FCA?

In this proceeding, the Comments of Staff, ICL, and CAPAI all spend a considerable amount of time discussing the different reasons why customer loads could increase or decrease that do not relate to DSM activities. Some of these non-DSM related variables include building code changes, federal weatherization programs, tax incentives and appliance rebates, federal marketing programs, technological changes, substitutions between gas and electric equipment, rate design changes, shifts in the economy, and other behavioral changes. Idaho Power can assist in promoting many of the above-mentioned non-DSM program initiatives that benefit customers. The Company *should* be encouraged to pursue all legitimate load reducing activities and the FCA mechanism *should* appropriately capture all of the impacts to fixed cost recovery that flow from these activities. Removing as many disincentives to load reduction activities as possible is in the public interest.

4. <u>Simplicity Benefits All Stakeholders</u>.

During the workshops that led up to the Stipulation that was approved by the Commission in Order No. 30267, all of the parties acknowledged that developing a "decoupling" mechanism like the FCA would always be a tradeoff between complexity–continuous analysis to provide some evidence that the FCA was the predominant driver of load reductions directly related to utility DSM programs–and simplicity–a decoupling program somewhat less rigorous in its analytic approach but more manageable and less prone to unintended and even perverse consequences. In the end, the parties agreed that simple is better and filed the Stipulation implementing the FCA. Unfortunately, the Comments of Staff, CAPAI, and ICL seem to be urging the Commission to return to the path of complexity. Staff recommends that the pilot program be extended for two years and during this time the Company began "isolating the impact of these changes on residential and small general service consumption by conducting price elasticity, economic, load research, and end-use market research studies." (Staff Comments at p. 12.) CAPAI and ICL recommend that the pilot program be extended for one year. Like Staff, CAPAI and ICL recommend that numerous new studies, analyses, and workshops be undertaken to address the issues raised in their respective Comments. Staff, ICL, and CAPAI all recommend that the Commission reject Idaho Power's request to make the current FCA permanent. Idaho Power questions whether undertaking multiple new analyses, studies, and workshops will really produce results that are meaningful to the purpose of the FCA. Idaho Power acknowledges that there will always be a number of variables, such as those cited above, that would change the Company's loads, either positively or negatively, that are not directly related to DSM activities. Expending substantial time and resources attempting to precisely parse the relative contributions to load increases or decreases of all the potential variables does not seem particularly useful. The evidence is clear that the FCA is doing what it was intended to do. The FCA has disconnected the recovery of fixed costs from volumetric energy sales, thereby eliminating the disincentive for the Company to pursue DSM and other load reducing activities. It has induced the Company to facilitate its DSM programs in a very material way. It provides rate stabilization. The FCA is doing all of those things with a simple, straightforward mechanism, consistent with the agreed-upon criteria that a decoupling mechanism should be simple. While additional analyses related to specific costs/benefits may be appropriate in a performance incentive mechanism, they are not adding value to an FCA mechanism whose basic purpose is to true-up fixed cost recovery.

III. MAKING THE FCA PERMANENT WILL BENEFIT CUSTOMERS

5. Making the FCA Permanent Does Not Preclude Future Adjustments.

While the evidence shows that the FCA is working as intended, Idaho Power concurs that some fine tuning of the mechanism may be reasonable. However, there is no reason that any additional analyses, studies, and workshops cannot be undertaken after the Commission has made the FCA program permanent. Idaho Power has made a number of material adjustments to its power cost adjustment ("PCA") true-up mechanism after the mechanism was approved on a permanent basis. A permanent FCA can be adjusted in the same way.

A good case study of how an adjustment to a permanent FCA would work is the FCA-LGAR issue raised by Staff. In its Comments in this case, Staff noted some concern regarding the interaction between the load growth adjustment rate ("LGAR") in the Company's PCA and the FCA. In Rocky Mountain Power's PCA case, PAC-E-10-01, the Staff noted the same concern. In Order No. 31033, the Commission directed the Staff to hold a workshop for Idaho Power, Avista, and Rocky Mountain to discuss the LGAR and, in Idaho Power's case, the FCA mechanism. As this demonstrates, even if the FCA is a permanent rate schedule, ample opportunity exists to address situations like the FCA/LGAR question as they arise.

6. <u>There is Risk in Continuing the FCA as a Pilot Program Rather than Granting It Permanent Status</u>.

As the Commission noted in Order No. 30267, "The annual FCA true-up mechanism assures a more stable utility recovery of fixed costs that are now recovered in the energy rate component of residential and small general service customers." (Order No. 30267 at p. 13.) The stable utility recovery of fixed costs referenced in the above quote rests on a foundation of predictability and certainty. Denying permanent status for the FCA and instead continuing it as a temporary pilot program reintroduces the element of uncertainty. Is the disincentive that everyone agrees exists really going to be eliminated?

Fortunately, the Company, the Commission, and the Intervenors <u>can</u> have it both ways. The Commission can approve the FCA as a permanent program while at the same time allowing the stakeholders to explore potential adjustments to the mechanism, based on new evidence and experience, which maintains the integrity of the FCA.

There is risk in continuing the FCA as a pilot program rather than granting it permanent status. Credit rating agencies and stock research analysts view the FCA favorably. (See Attachment Nos. 1 and 5.) Continuing the FCA in a pilot project mode adds an element of uncertainty to the Commission's long-run commitment to the FCA. Allowing the FCA to become a permanent mechanism with the understanding that there are some aspects of the mechanism that should receive further consideration, and perhaps adjustment, would be beneficial. Maintaining the program in limbo is not beneficial.

7. Changing the Way the FCA Is Presented on Customer Bills Will Confuse Customers.

To reduce customer confusion, Staff recommends that the FCA be removed from the Energy Efficiency Services line item and combined with the PCA to form an "Annual Adjustment Charge." The Company believes this change would actually be more confusing to customers as these adjustments can easily go in opposite directions. Idaho Power's preference would be to leave the bill presentment of the FCA as it is for now, particularly if there will be follow-up regulatory activity related to the FCA mechanism. If the Commission is persuaded to make a change to bill presentation at this time, the Company's believes that a separate line item for the FCA is preferable to combining its impact with the PCA.

IV. CONCLUSION

Idaho Power's FCA has operated as intended during its three-year pilot period. The FCA's principal purpose of removing disincentives to energy efficiency investments and other load reducing activities undertaken by the Company to benefit its customers has been accomplished. The proof of this accomplishment is increased energy efficiency activity, higher levels of customer education, and new pricing initiatives – all targeted at using electricity wisely. The disincentive is removed by essentially creating a new residential/small commercial rate design where fixed costs are recovered based upon customers served versus kilowatt-hours consumed.

The mechanism meets the criteria established during the original workshops. Customers are better off because lower cost options are pursued vigorously and bills are stabilized. The Company has an improved fixed cost recovery mechanism which–absent the ability to dramatically change its pricing structure–lowers risks. The mechanism is simple, symmetrical, easy to administer, and has not resulted in any unintended consequences. Disincentives have been removed and energy efficiency activities enhanced. Its implementation has been widely acknowledged as a positive regulatory policy.

Idaho Power maintains it is time to make the mechanism permanent. The Company welcomes opportunities to enhance the FCA through future collaborative efforts and accepts the challenge of doing a better job of explaining the mechanism to customers and other interested parties.

DATED at Boise, Idaho, this 9th day of April 2010.

BARTON L. KLINE
Attorney for Idaho Power Company

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on this 9th day of April 2010 I served a true and correct copy of the foregoing REPLY COMMENTS OF IDAHO POWER COMPANY upon the following named parties by the method indicated below, and addressed to the following:

Commission Staff Weldon B. Stutzman Deputy Attorney General Idaho Public Utilities Commission 472 West Washington P.O. Box 83720 Boise, Idaho 83720-0074	_X_ Hand Delivered ____U.S. Mail ____Overnight Mail ____FAX _X_ Email Weldon.stutzman@puc.idaho.gov
Snake River Alliance Ken Miller Snake River Alliance P.O. Box 1731 Boise, Idaho 83701	____Hand Delivered _X_ U.S. Mail ____Overnight Mail ____FAX _X_ Email kmiller@snakeriveralliance.org
Community Action Partnership Association Of Idaho Brad M. Purdy Attorney at Law 2019 North 17th Street Boise, Idaho 83702	____Hand Delivered _X_ U.S. Mail ____Overnight Mail ____FAX _X_ Email bmpurdy@hotmail.com
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Barton L. Kline

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-09-28

IDAHO POWER COMPANY

ATTACHMENT NO. 1

MOODY'S
INVESTORS SERVICE

Credit Opinion: IDACORP, Inc.

Global Credit Research - 31 Mar 2010

Boise, Idaho, United States

Ratings

Category	**Moody's Rating**
Outlook	Stable
Issuer Rating	Baa2
Sr Unsec Bank Credit Facility	Baa2
Senior Unsecured Shelf	(P)Baa2
Commercial Paper	P-2
Idaho Power Company	
Outlook	Stable
Issuer Rating	Baa1
First Mortgage Bonds	A2
Senior Secured	A2
Sr Unsec Bank Credit Facility	Baa1
Senior Unsecured Shelf	(P)Baa1
Commercial Paper	P-2

Contacts

Analyst	**Phone**
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William L. Hess/New York	212.553.3837

Key Indicators

[1]IDACORP, Inc.

	2009	**2008**	**2007**	**2006**
(CFO Pre-W/C + Interest) / Interest Expense	**4.5x**	**2.7x**	**2.2x**	**3.5x**
(CFO Pre-W/C) / Debt	**19%**	**10%**	**6%**	**14%**
(CFO Pre-W/C - Dividends) / Debt	**16%**	**7%**	**3%**	**10%**
Debt / Book Capitalization	**46%**	**47%**	**45%**	**43%**

[1] All ratios calculated in accordance with the Regulated Electric and Gas Utilities Rating Methodology using Moody's standard adjustments

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Dominant influence of regulated utility subsidiary with relatively low business risk profile

More regulatory support through base rate increases and improvements to cost recovery mechanisms

Significant planned utility capital expenditures supported in part through Senate Bill 1123

Stronger credit metrics and liquidity expected to remain sufficient

Corporate Profile

IDACORP, Inc. (IDA) is a holding company whose principal operating subsidiary is Idaho Power Company (IPC), a fully integrated regulated electric utility. On a stand-alone basis, IPC represents the substantial majority of IDA's consolidated revenues, net income, and assets. IDA's other subsidiaries include: IDACORP Financial Services, an investor in affordable housing projects and other real estate investments; and Ida-West Energy, an operator of nine small hydro-electric generation projects that satisfy the requirements of the Public Utility Regulatory Policies Act of 1978. IPC's service territory encompasses southern Idaho and eastern Oregon and its rates are regulated by the Idaho Public Utilities Commission (IPUC) and the Oregon Public Utility Commission (OPUC).

SUMMARY RATING RATIONALE

IDA's Baa2 senior unsecured debt rating primarily reflects our assessment of key factors affecting the credit quality of IPC (Baa1 senior unsecured debt rating), which is its single largest subsidiary. The rating also takes into account the structural subordination of IDA's obligations in right of payment to those of IPC and other subsidiaries. IPC's Baa1 senior unsecured rating reflects its relatively low business risk profile, the company's cost advantage over most of its national peers, and the improved cost recovery treatment it has been receiving from state regulators in both jurisdictions, particularly as it relates to several regulatory decisions in 2009 and early 2010. Key credit metrics strengthened significantly in 2009 and should be sustainable for 2010, despite the ongoing financial and operating risks of executing a large capital program. Hydro conditions remain a key rating concern given the extent of IPC's dependence on hydroelectric facilities, as does the higher than historical average planned capital spending, even as some projects have experienced curtailment or delays. Moreover, continued conservative financing strategies will be necessary to sustain the company's improved credit metrics, which rebounded in 2009 to levels more in line with peers in the Baa1 rating category. To accomplish this, continued support from state regulators in anticipated future general rate cases will also remain an important rating driver.

DETAILED RATING CONSIDERATIONS

LOW BUSINESS RISK PROFILE OF DOMINANT UTILITY SUBSIDIARY

The low business risk profile of IDA's largest subsidiary, IPC, is influenced by its heavy reliance on low-cost hydro-electric power for its generating needs. IPC normally generates nearly half of its electricity from 17 hydro-electric developments on the Snake River and its tributaries. IPC also serves a portion of its electric load from three coal-fired power plants in Wyoming, Nevada, and Oregon, and from the natural-gas fired Bennett Mountain Power Plant and the Evander Andrews Power Complex in Mountain Home, Idaho. IPC is also the parent of Idaho Energy Resources Co., a joint venture partner in Bridger Coal Company, which supplies coal to the Jim Bridger generating plant owned in part by IPC. Moreover, IPC is not burdened with supporting any material debt load at the IDA level. IDA divested most of its prior investments in riskier non-regulated businesses during a three-year period covering 2005 - 2007, and has since made IPC its principal focus. The remaining non-regulated investments, which are relatively immaterial to our analysis, include independent power production at Ida-West Energy and affordable housing at IDACORP Financial Services.

SUPPORTIVE REGULATORY ENVIRONMENT BODES WELL FOR CREDIT QUALITY

Favorable regulatory practices in Idaho (IPC's principal jurisdiction), include: 1) a relatively swift 7-month statutory period governing rate cases; 2) frequent decisions based on settlements instead of litigated proceedings; 3) reasonable allowed returns on equity; 4) reliance on various cost tracking and adjustment mechanisms, periodic utilization of single-issue rate cases and partially forecast test years to avoid undue rate lag; and 5) pre-approval of future rate treatment for certain capital investments allowed under state law.

SUCCESSFUL INITIATIVES NOTED FOR 2009...

IDA's consolidated credit quality will continue to be influenced in part by the fact that the IPUC approved a total of 4.01% (about $27 million) in general rate increases for IPC during the first quarter of 2009, which reflected the outcome of the utility's 2008 general rate case filing. While this was about 40% of the $67 million requested, the decision was based on an allowed return on equity of 10.5% (in line with many other jurisdictions) and did include collection of about $10.6 million for AFUDC associated with hydro relicensing construction activities. Also, in May 2009 there were several favorable rate orders from the Idaho and Oregon commissions combined to address various other requests for revenue increases. These orders collectively approved rate increases of about $135 million effective June 1, 2009 and contributed to a solid rebound in IPC's and IDA's financial results for the year. Moreover, Senate Bill 1123 (SB 1123) became effective 7/1//2009. Under SB 1123, the IPUC may grant pre-approval of rate treatment for certain utility capital expenditures. We generally view pre-approval of rate treatment for a utility's future capital programs as a credit positive given the degree of assurance it would provide for cost recovery and the ability to earn a rate of return. (See below for further details on how SB 1123 was favorably applied to IPC's capex program).

The most significant of the May 2009 rate orders was the power cost adjustment (PCA) rate decision. Specifically, the IPUC approved the full amount of IPC's PCA filing, which amounted to $84.3 million above the current PCA rate. Importantly, IPC was able to use its most recent operating plan to forecast power supply expenses rather than the previous method based on forecast Brownlee Reservoir inflow and a regression formula. This change became effective in February 2009 after the IPUC agreed with IPC that the utility's plan was a better indicator of anticipated expenses and should create a better matching between actual costs incurred and the amounts in customers' rates. This practice will continue in future PCA filings; accordingly, future PCA balances should be considerably less and thereby reduce cash lag. Moreover, the IPUC revised the sharing formula under the PCA mechanism to 95%/5% (customers/shareholders) from 90%/10% previously, thereby reducing risk to investors. Lastly, the load growth adjustment rate (LGAR) is now determined formulaically based on total production expenses included in current base rates, which reduces regulatory risk previously associated with the LGAR. The current LGAR of $26.63 per MWh is reduced from the $28.14 per MWh level that would otherwise apply based on the formula agreed to by parties in an earlier approved stipulation. The significance of the LGAR is that it adjusts IPC's net power supply costs that are included in the annual PCA filings for differences between actual load and the load used in calculating existing base rates. The combination of anticipated better matching between actual net power supply costs incurred and load growth experienced with levels assumed in setting existing rates should allay concerns about potential negative effects on IPC's earnings and cash flow when larger mismatches occur.

The other revenue increases approved in May 2009 included: 1) an approved increase in IPC's Energy Efficiency Rider to 4.75% from 2.5%, establishing assurance for cost recovery of various energy efficiency programs; 2) adjustments under IPC's decoupling program aimed at de-linking revenues from volume; 3) revenue requirements to cover investments in advanced metering infrastructure; and 4) rate adjustments under the power cost adjustment mechanism in Oregon.

...AND MORE SUCCESS APPARENT TO DATE IN 2010

In lieu of filing another significant general rate case in Idaho in 2009, IPC successfully negotiated a settlement that was approved by the IPUC on 1/14/2010. We view this result as a credit positive as we believe it fortifies the collaborative working relationship with the IPUC, which is a heavily weighted factor in our Regulated Electric and Gas Utilities Rating Methodology published in August 2009 (the Rating Methodology). Although the settlement includes a two-year base rate freeze through 1/1/2012, it does not preclude the expected PCA and other rate mechanism filings that will occur regularly. Several other key features of the settlement included; 1) planned distributions of a portion of the expected 2010 PCA decrease to customers, with the balance returned to IPC to provide rate relief; 2) a means to reset base net power supply costs for future PCA filings; 3) approval to use accelerated amortization of investment tax credits to achieve an ROE in the Idaho jurisdiction of 9.5%; and 4) a sharing mechanism for Idaho based earnings in excess of the allowed 10.5% ROE.

In the smaller Oregon jurisdiction, IPC was able to favorably settle its rate case originally filed in July 2009, when a proposed settlement was approved by the OPUC on 2/24/2010. The approval allowed IPC to increase its base electric rates in Oregon by $5 million effective 3/1/2010, based on an allowed ROE of 10.175% and an assumed 49.8% equity component in the capital structure. The allowed ROE compares favorably to IPC's former allowed ROE in Oregon of 10%.

CAPEX PLANS REMAIN SIGNIFICANT EVEN AS TRANSMISSION PROJECTS UNFOLD SLOWLY

IDA has scaled back its planned utility-related capital spending in line with economic conditions. Still, the level of spending could exceed $1.0 billion over the next three years as the company is moving ahead with construction of the 300-330 megawatt natural gas plant at Langley Gulch. The estimated expense for that project alone is $427 million including AFUDC, which could be in service by 7/1/2012. The IPUC approved a certificate of public convenience and necessity (CPCN) for this plant in September 2009. In granting the CPCN, the IPUC relied upon SB 1123 to pre-approve inclusion of up to $396.6 million of construction costs in IPC's rate base concurrent with the commercial operation date for the Langley Gulch plant. We view this pre-approval as credit positive because it reduces the regulatory and financial risk that would otherwise be associated with this investment. Importantly, any investment in excess of the pre-approved amount would not necessarily be disallowed, but recovery of and return on the excess would be subject to a separate rate proceeding. Other than the early stage spending relating to two major transmission projects (i.e. Boardman to Hemingway and Gateway West), IPC's capex budget for 2010 - 2012 includes ongoing investments in other basic utility related distribution and general infrastructure, including advanced metering infrastructure.

We understand management reassessed the capital program during 2009, resulting in delays related to the 500 kV Boardman to Hemingway Line, which stretches out the spending to later years and reduces near term financing needs. IPC still expects to seek partners for up to 50 to 70 percent of this project, which would further reduce capital needs.

As in the past, a mix of debt and equity infusion from IDA is expected to be used to meet external funding required while targeting a capital structure comprised of a percentage of debt and equity close to current levels. Also, given the level of planned capex, we expect that IPC will likely need to file for additional general rate increases to take effect in Idaho once the settlement period under its current rate agreement expires.

KEY CREDIT METRICS HAVE STRENGTHENED; VOLATILITY OF PAST YEARS SHOULD SUBSIDE

A variety of factors contributed to substantial strengthening of IDA's key credit metrics in 2009, including general rate relief, cash recovery of regulatory assets, and favorable impact to cash flow from deferred income taxes and investment tax credits. Specifically, IDA's CFO Pre-W/C plus interest to interest and CFO Pre-W/C to debt for FY 2009 were 4.5x and 18.9%, respectively, bringing them to a level considered strong vis-`-vis its Baa2 rating according to the Rating Methodology. Although the level of IDA's metrics continues to be constrained by a fairly significant standard adjustment for underfunded pension obligations, the underfunded pension position is not cause for undue concern at this stage because the IPUC provides for timely recovery of cash contributions through the rate process. Meanwhile, IPC is also in discussions with the IPUC about establishing a tracking mechanism for pension expenses. Also, as the effects of IPC's 2010 settlement take effect over the balance of this year and as other regularly scheduled rate adjustments occur, we anticipate that IDA's CFO Pre-W/C plus interest to interest and CFO Pre-W/C to debt coverage metrics can be maintained close to FYE 2009 levels, respectively, for FY 2010.

IDA's debt leverage ratio stood at 46.1% as of 12/31/2009. This level represents a slight improvement compared to the 47% at 12/31/2008, as higher retained earnings and additional common equity sold in 2009 offset the slight increase in debt. Importantly, the metric is comfortably positioned relative to the range that we typically observe for Baa-rated holding companies with predominantly regulated electric utility subsidiaries under the Rating Methodology. Even if debt levels creep slightly higher as capex is funded, management remains committed to keeping close to the current mix of debt and equity in its capital structure.

Liquidity

On balance, IDA has sufficient liquidity, including cash on hand, dividends periodically provided by IPC and its other operating subsidiaries, plus ample unused capacity under committed bank facilities at the parent level and at IPC. IDA maintains access to short-term funding and alternative liquidity for commercial paper outstanding through a $100 million facility, which terminates on April 25, 2012. At February 19, 2010, there were no borrowings under IDA's facility but $25 million of commercial paper was outstanding. The IPC facility is currently a $300 million credit agreement that terminates on April 25, 2012. At February 19, 2010, no loans were outstanding on IPC's facility nor was there any commercial paper outstanding. The only financial covenant in each facility limits the debt to total capitalization ratio as defined to 65%. At December 31, 2009, the leverage ratios for both IDA and IPC were 51% and 53%, respectively.

IDA has attempted to minimize its reliance on short-term debt, especially in support of capital expenditures at IPC, through the periodic issuance of common equity. We expect that this strategy will continue, including in part through issuance of common stock under a continuous equity program and from dividend reinvestment program (DRIP) common stock offerings. Over the next four quarters, we expect IDA's commercial paper amounts outstanding will continue to be influenced primarily by the timing of tax payments and dividends to shareholders. IDA has no standalone long-term debt outstanding and no plans to issue holding company long-term debt in the foreseeable future. IPC has a fairly manageable debt maturity schedule over the near term. The utility's next scheduled debt maturities are in March 2011 when $120 million of FMBs are due and November 2012 when another $100 million of FMBs mature. We understand that management plans to explore market opportunities to pre-fund the scheduled 2011 maturity this year. Meanwhile, IPC's issuance of $130 million of FMBs in 2009 effectively prefunded the long-term financing needs for 2010. Looking forward, construction of the Langley Gulch plant primarily drives the capital needs in 2011 and 2012 and we assume conservative financing strategies will continue to guide future funding.

Rating Outlook

IDA's stable rating outlook mirrors the stable outlook for IPC, its principal subsidiary. IPC's stable rating outlook reflects more supportive regulation, especially in Idaho, which should help avoid past volatility in key metrics, instead keeping them closer in line with similarly rated peers. The execution risks associated with ongoing capital spending projects and external financing needs are tempered by assurances of future rate treatment for the Langley Gulch plant and anticipated conservative funding strategies. The stable rating outlook for IDA also takes into account the fact that

IPC provides the substantial majority of the parent's earnings and cash flow. As a result, IPC substantially drives the credit rating and outlook of its parent.

What Could Change the Rating - Up

Because IDA is largely dependent on IPC for cash flow in the form of dividends, any improvement in the parent's ratings will be considered largely in the context of our assessment of IPC's credit quality. Although a rating upgrade is unlikely in the near term, IDA's outlook could turn to positive if the benefits from recent rate relief for IPC carry through and there are no material changes in the degree of regulatory supportiveness in IPC's future rate filings. In terms of key metrics, the outlook could turn to positive if CFO Pre-WC plus interest to interest and CFO Pre-W/C to debt, on a three-year average basis, can be sustained above 3.5x and 15%, respectively.

What Could Change the Rating - Down

The rating could be revised down if the improved regulatory support for IPC wanes or if conservative funding strategies are not adhered to, thus contributing to undue pressure on IDA's key metrics. For example, if IDA's CFO Pre-W/C plus interest to interest and CFO Pre-W/C to debt metrics fall below 3.5x and 15%, respectively, for an extended period of time, then a downgrade could occur. A rating downgrade could also occur if the company manages its significant utility capex program in a manner that is inconsistent with its current credit profile. Also, any unexpected shift by IDA to material debt-financed investments in other non-utility businesses, or a material acceleration of the utility's capex program wherein IDA's consolidated debt level is increased significantly above its current level and inflates its debt/capitalization ratio to well above 50% on a sustainable basis, could lead to a negative rating action.

Rating Factors

IDACORP, Inc.

Regulated Electric and Gas Utilities	Aaa	Aa	A	Baa	Ba	B
Factor 1: Regulatory Framework (25%)				X		
Factor 2: Ability to Recover Costs and Earn Returns (25%)				X		
Factor 3: Diversification (10%)						
a) Market Position (5%)				X		
b) Generation and Fuel Diversity (5%)			X			
Factor 4: Financial Strength, Liquidity and Key Financial Metrics (40%)						
a) Liquidity (10%)				X		
b) CFO pre-WC + Interest / Ineterest (7.5%) (3yr Avg)				X		
c) CFO pre-WC / Debt (7.5%) (3yr Avg)					X	
d) CFO pre-WC - Dividends / Debt (7.5%) (3yr Avg)					X	
e) Debt / Capitalization or Debt / RAV (7.5%) (3yr Avg)				X		
Rating:						
a) Methodology Implied Senior Unsecured Rating				**Baa2**		
b) Actual Unsecured Rating				**Baa2**		

MOODY'S
INVESTORS SERVICE

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-09-28

IDAHO POWER COMPANY

ATTACHMENT NO. 2

APPENDIX I

C. L. "BUTCH" OTTER
GOVERNOR

March 19, 2009

The Honorable Steven Chu
Secretary
U.S. Department of Energy
1000 Independence Avenue, S.W.
Washington, D.C. 20585

VIA FACSIMILE & U.S. MAIL

Re: The State of Idaho's Energy Program Assurances

Dear Secretary Chu,

As a condition of receiving Idaho's share of the $3.1 billion funding for the State Energy Program (SEP) under the American Recovery and Renewal Act of 2009 (H.R. 1)(ARRA), I am providing the following assurances. I have written to our public utility commission and requested that they continue their successful decoupling efforts and consider additional actions to promote energy efficiency, consistent with the Federal statutory language contained in H.R. 1 and their obligations to maintain just and reasonable rates, while protecting the public. I have also written the appropriate state agencies and requested that they consider actions to improve building energy codes, consistent with State law and State Constitutional requirements, and to consider the statutory language contained in ARRA.

We are prioritizing our energy investments to take advantage of existing programs and expand programs where appropriate. Our State is committed to a robust improvement in energy efficiency and renewable energy, as well as a balanced State energy policy. I want to assure you that, within the limits of my authority, we will move forward in these critical areas.

We look forward to immediate distribution of the Federal SEP funds to permit my State to make progress in energy efficiency and renewable energy.

As Always – Idaho, "Esto Perpetua"

CLO/sg

C.L. "Butch" Otter
Governor of Idaho

cc: Gil Sperling
Director, Office of Weatherization and Intergovernmental Programs
U.S. Department of Energy
State Energy Director
David Terry, Executive Director
National Association of State Energy Officials

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-09-28

IDAHO POWER COMPANY

ATTACHMENT NO. 3

December 11, 2009

Senators and Representatives,

The 2007 Idaho Energy Plan, written in compliance with House Concurrent Resolution 62, directs that the "Energy Division (now the Office of Energy Resources) and the Public Utilities Commission should report to the Legislature every two years on the progress of Idaho state agencies, energy providers and energy consumers implementing the recommendations in this Energy Plan." *(Action Item I-3, page 65, 2007 Idaho Energy Plan.)*

The Office of Energy Resources and the Public Utilities Commission, acting jointly, hereby submit the 2009 report. We consider this biennial filing to be a critical component to helping achieve the state's goal of ensuring a reliable, low-cost energy supply, protecting the environment and promoting economic growth. Filing this report every two years, as the Energy Plan requires, will help us evaluate our progress and set future goals.

You will find that we firmly believe the State is making progress in meeting many of the plan's objectives. We also do not hesitate to point out those areas where some of the plan's recommendations are best met with other approaches and methodologies.

As stated in Energy Plan's introductory letter from the Interim Committee on Energy, Environment and Technology, "Idaho's existing energy resource base has resulted in some of the lowest electricity and natural gas prices in the country, providing enormous benefit to customers." To maintain that benefit and yet meet the significant challenges of the future to provide energy supply at reasonable rates, the Office of Energy Resources and the PUC concurs with the Committee's statement that we need a "pragmatic, common-sense approach." We believe that the actions taken thus far, and those planned, will prepare us well for the future.

Sincerely,

Paul Kjellander
Director, Idaho Office of Energy Resources

Jim Kempton
President, Idaho Public Utilities Commission

conservation and renewable resource investments and in calculating payments to qualifying facilities under the federal Public Utility Regulatory Policy Act (PURPA).

Because ***avoided cost*** is defined as the cost of the next unit of power a utility would acquire if there were a need for additional generation, it is often argued that avoided cost used to value a qualifying small-power PURPA project should also be used to evaluate cost-effectiveness of proposed conservation projects or renewable resource options. Under this proposition, it is logical to suggest that an "avoided cost benchmark" for each utility could be established and updated periodically. In actual practice, the benchmark concept is oversimplified.

To accommodate small (10MW or less) PURPA projects in Idaho, the Commission has established a ***published avoided-cost rate*** based on a surrogate avoided resource (SAR) that is currently defined as a combined-cycle combustion gas turbine. This over-simplified methodology works relatively well for small base load-type resources. It does not work well for variable renewable energy resources because of the difference in SAR operating characteristics. Instead, the utility uses its Integrated Resource Plan process with actual planned resources and forecasted market prices to establish an avoided cost ***for each*** proposed renewable project. The IRP and its various parameters are published and periodically updated. The avoided cost associated with this methodology more accurately reflects the generation costs that a utility expects to avoid by acquiring any other resource regardless of operating characteristics. It also forms the basis of the cost-efficient resource acquisition calculations conducted to meet the standards of E-1.

Published PURPA avoided- cost rates for small qualifying facilities were most recently updated in March 2009 in response to a joint petition from the investor-owned utilities and other parties to 1) update the non-fuel cost components of the SAR and 2) reflect the new natural gas price forecast from the Northwest Power and Conservation Council.[2] Utility IRPs used to determine actual planned generation costs avoided by proposed renewable resources are updated every two years.

The PUC is continuously evaluating both the processes used by utilities to deliver demand-side programs and the assumptions and measurements used to determine cost-effectiveness. The Commission is currently working with utilities to establish procedures to annually report demand-side process improvement and to periodically update program impact evaluation, measurement and verification (EMV) practices.

E-4 – The Idaho PUC should establish appropriate shareholder incentives for investor-owned utilities that achieve the conservation targets established by the PUC. Shareholder incentives may include, but are not limited to:

> *i. Recovery of revenues lost due to reduced sales resulting from conservation investments;*
> *ii. Capitalization of conservation expenditures;*

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[2] Case No. GNR-E-08-02, Order No. 30744. For press release, see Appendix C.

iii. A share of the net societal benefits attributable to the utility's energy efficiency programs;
iv. An increase in the utility's return on equity for each year in which savings targets are met; or
v. "Decoupling" of utility revenues from sales.

The PUC has not established "conservation targets" as explained under E-2 except to "achieve all available DSM, conservation and energy efficiency."

However, in March 2007, the Commission adopted one of the first electric decoupling mechanisms in the nation designed to remove financial disincentives for Idaho Power Company to implement energy efficiency programs. (Case No. IPC-E-04-15, Order No. 30267) The Fixed Cost Adjustment (FCA) is a mechanism that separates utility sales from revenues by allowing Idaho Power to recover its fixed costs of providing power, as established in the most recent rate case, regardless of reduced sales due to energy efficiency and demand side management programs. In exchange for allowing Idaho Power this recovery, the utility committed to aggressively and cost-effectively pursue energy efficiency and demand side management programs. Idaho and the PUC are soon to be in the final year of a three-year pilot and Idaho Power has applied to have the FCA made permanent.[3]

Also, each of the three major investor-owned utilities has energy efficiency riders in place that allow them to recover costs of demand-side management, conservation and energy efficiency programs. The Commission has been willing to grant utility requests to significantly increase these riders over recent years to encourage conservation, energy efficiency and DSM.

On June 1, 2009, the Commission increased the Idaho Power rider from 2.5 percent to 4.75 percent. According to Idaho Power's application, energy efficiency programs in 2008 resulted in 107,484 megawatt-hours of energy savings, a 72 percent increase over the 2007 total of 62,544 MWh. DSM programs that reduce demand on Idaho Power's system provided 58 megawatts of demand reduction in 2008 compared to 48 MW in 2007. [4]

The commission recently completed a review of Avista's DSM and energy efficiency programs in conjunction with its earlier approval of an increase in the rider from 2.24 percent to 3.27 percent. Avista's DSM and efficiency efforts are based on providing financial incentives or rebates for customer participation in more than 30 programs. Avista continues to exceed targets in electric and gas savings as the result of these programs for its Washington and Idaho customers. More than 110 average megawatts of demand-side management programs are now in place on the company's total retail average load (during 2008) of 1,100 average megawatts.[5]

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[3] Order approving FCA in Case No. IPC-E-04-15, Order No. 30267. For press release, see Appendix D. Press release re: Idaho Power application to make FCA permanent, Case No. IPC-E-09-28, see Appendix E
[4] Most recent Idaho Power energy efficiency rider increase, IPC-E-09-05, Order No. 30814. For press release, see Appendix F.
[5] Case No. AVU-E-09-06. For Order 30918, see Appendix G.

In May 2008, the Commission authorized an increase in PacifiCorp's (Rocky Mountain Power) rider from 1.5 percent to 3.72 percent. By implementing programs funded by the rider, the company estimates it will save 13,140 megawatt-hours per year. At the former 1.5 percent, the rider funded programs that saved about 8,000 MWh during 2007.[6]

The independent American Council for an Energy-Efficient Economy (www.aceee.org) ranks Idaho 13th among the 50 states and the District of Columbia in its 2008 State Energy Efficiency Scorecard. More noteworthy, is the report's declaration that Idaho is the "most improved" state, having moved up 12 spots from the 2007 scorecard. The link to that report is as follows:

http://aceee.org/pubs/e086_es.pdf

While the PUC does not establish explicit shareholder incentives, the aggressiveness of the utility is a factor in setting Return On Equity (ROE) in rate cases. In Order No. 22299, the Commission said, *"Accordingly, we take this opportunity to notify our regulated electric utilities that in future rate cases we will take into account the utility's commitment to energy conservation in determining the allowed rate of return. A utility that aggressively addresses the issues and concerns found in this Order, all other things being equal, may expect the allowance of higher return than might otherwise be allowed."*

Also encouraging to shareholders is the fact that increased frequency of rate cases has decreased the potential for lost recovery of fixed costs due to demand-side achievements in between rate cases.

All three IOUs purchase power under contract from renewable resources. These costs are allocated to annual Power Cost Adjustment (PCA) accounts until the costs are placed in base rates following the next rate case. (A mechanism like a PCA, called the Energy Cost Adjustment Mechanism, has just been approved for PacifiCorp, Order No. 30904) For PURPA contracts, the utilities get 100 percent recovery of prudent expenses through the PCA until costs are fully included in base rates.

Additionally, the Idaho Office of Energy Resources (OER) initiated a series of workshops to develop an appropriate incentive mechanism to optimize cost-effective demand-side management activities for Idaho Power Company. The results of the workshops may be presented to the PUC for its consideration in regulatory proceedings.

The goal of the workshops is to explore and potentially develop an incentive mechanism for Idaho Power's investment in DSM activities that represents a reasonable and attainable incentive, and that balances and aligns utility, customer and societal interests. Parties indentified from previous PUC cases were invited to participate in the workshops.

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[6] Case No. PAC-E-08-01, Order No. 30543. For press release, see Appendix H.

These workshops are also intended to advance commitments made by the State of Idaho in relationship to acceptance of funds provided by the American Reinvestment and Recovery Act. In a letter addressed to the United States Secretary of Energy, Idaho Governor C.L. "Butch" Otter signed assurances that the state would seek to implement a general policy that ensures that utility financial incentives are aligned with helping customers use energy more efficiently. [7]

E-5 – The Idaho PUC should support market transformation programs that provide cost effective energy savings to Idaho citizens.

The PUC continues to allow Idaho's regulated utilities to fund and actively participate in the Northwest Energy Efficiency Alliance (NEEA), a regional market transformation entity. PUC staff actively monitors NEEA's programs and decision-making processes in assessing the benefits to Idaho customers. All three IOUs have or are currently negotiating new 5-year contracts with NEEA to continue market transformation efforts. The PUC staff consistently supports NEEA's efforts as cost-effective and prudent. However, the commission continues to evaluate NEEA's cost-effectiveness calculation methods and its past method of allocating savings to utility service areas. In this regard, utilities are encouraged to compare the cost-effectiveness of NEEA programs to programs that could otherwise be provided by the utilities within their own service areas.

To further support regional market transformation programs, Gov. Otter exercised his authority to appoint a member to the NEEA board. Under provisions of the NEEA bylaws, Idaho and Montana "rotate" a seat on the NEEA board. Governor Otter's recommendation to the NEEA Board was approved in October 2009. [8]

E-6 – The Idaho PUC and Idaho utilities should consider adopting rate designs that encourage more efficient use of energy.

The PUC continues to consider the affects of rate design on electricity consumption and peak-energy demand. The PUC recognizes that, ultimately, cost-based and time-varying rates will provide important price signals, but until customer meters are upgraded to accommodate such dynamic pricing, other rate designs (e.g. tiered rates, seasonal rates) have been implemented.

In conjunction with Idaho Power's 2008 rate case, the Commission re-instituted tiered rates in early 2009 for Idaho Power customers. Customers pay the lower rate for use below 800 kWh. The next highest rate is for use between 801 and 2000 kWh. All use above 2000 kWh is priced at the highest level.[9]

[7] Assurance letter dated March 19, 2009. See Appendix I.
[8] Letter from NEEA acknowledging appointment dated October 21, 2009. See Appendix J.
[9] IPC-E-08-10, Order No. 30722. For press release, see Appendix K.

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(3) savings to the taxpayers of the United States resulting from mandated improvements under this title and the amendments made by this title.

(b) SUBMISSION.—The report shall be submitted—

(1) to the Director at such time as the Director requires;

(2) in electronic, not paper, format; and

(3) consistent with related reporting requirements.

42 USC 17144.

SEC. 528. OMB GOVERNMENT EFFICIENCY REPORTS AND SCORECARDS.

(a) REPORTS.—Not later than April 1 of each year, the Director of the Office of Management and Budget shall submit an annual Government efficiency report to the Committee on Oversight and Government Reform of the House of Representatives and the Committee on Governmental Affairs of the Senate, which shall contain—

(1) a summary of the information reported by agencies under section 527;

(2) an evaluation of the overall progress of the Federal Government toward achieving the goals of this title and the amendments made by this title; and

(3) recommendations for additional actions necessary to meet the goals of this title and the amendments made by this title.

(b) SCORECARDS.—The Director of the Office of Management and Budget shall include in any annual energy scorecard the Director is otherwise required to submit a description of the compliance of each agency with the requirements of this title and the amendments made by this title.

SEC. 529. ELECTRICITY SECTOR DEMAND RESPONSE.

(a) IN GENERAL.—Title V of the National Energy Conservation Policy Act (42 U.S.C. 8241 et seq.) is amended by adding at the end the following:

"PART 5—PEAK DEMAND REDUCTION

42 USC 8279.

"SEC. 571. NATIONAL ACTION PLAN FOR DEMAND RESPONSE.

"(a) NATIONAL ASSESSMENT AND REPORT.—The Federal Energy Regulatory Commission ('Commission') shall conduct a National Assessment of Demand Response. The Commission shall, within 18 months of the date of enactment of this part, submit a report to Congress that includes each of the following:

"(1) Estimation of nationwide demand response potential in 5 and 10 year horizons, including data on a State-by-State basis, and a methodology for updates of such estimates on an annual basis.

"(2) Estimation of how much of this potential can be achieved within 5 and 10 years after the enactment of this part accompanied by specific policy recommendations that if implemented can achieve the estimated potential. Such recommendations shall include options for funding and/or incentives for the development of demand response resources.

"(3) The Commission shall further note any barriers to demand response programs offering flexible, non-discriminatory, and fairly compensatory terms for the services and benefits made available, and shall provide recommendations for overcoming such barriers.

"(4) The Commission shall seek to take advantage of preexisting research and ongoing work, and shall insure that there is no duplication of effort.

"(b) NATIONAL ACTION PLAN ON DEMAND RESPONSE.—The Commission shall further develop a National Action Plan on Demand Response, soliciting and accepting input and participation from a broad range of industry stakeholders, State regulatory utility commissioners, and non-governmental groups. The Commission shall seek consensus where possible, and decide on optimum solutions to issues that defy consensus. Such Plan shall be completed within 1 year after the completion of the National Assessment of Demand Response, and shall meet each of the following objectives:

"(1) Identification of requirements for technical assistance to States to allow them to maximize the amount of demand response resources that can be developed and deployed.

"(2) Design and identification of requirements for implementation of a national communications program that includes broad-based customer education and support.

"(3) Development or identification of analytical tools, information, model regulatory provisions, model contracts, and other support materials for use by customers, States, utilities and demand response providers.

"(c) Upon completion, the National Action Plan on Demand Response shall be published, together with any favorable and dissenting comments submitted by participants in its preparation. Publication.
Six months after publication, the Commission, together with the Secretary of Energy, shall submit to Congress a proposal to implement the Action Plan, including specific proposed assignments of responsibility, proposed budget amounts, and any agreements secured for participation from State and other participants. Deadline. Proposal.

"(d) AUTHORIZATION.—There are authorized to be appropriated to the Commission to carry out this section not more than $10,000,000 for each of the fiscal years 2008, 2009, and 2010.".

(b) TABLE OF CONTENTS.—The table of contents for the National Energy Conservation Policy Act (42 U.S.C. 8201 note) is amended by adding after the items relating to part 4 of title V the following:

Subtitle D—Energy Efficiency of Public Institutions

SEC. 531. REAUTHORIZATION OF STATE ENERGY PROGRAMS.

Section 365(f) of the Energy Policy and Conservation Act (42 U.S.C. 6325(f)) is amended by striking "$100,000,000 for each of the fiscal years 2006 and 2007 and $125,000,000 for fiscal year 2008" and inserting "$125,000,000 for each of fiscal years 2007 through 2012".

SEC. 532. UTILITY ENERGY EFFICIENCY PROGRAMS.

(a) ELECTRIC UTILITIES.—Section 111(d) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2621(d)) is amended by adding at the end the following:

"(16) INTEGRATED RESOURCE PLANNING.—Each electric utility shall—

"(A) integrate energy efficiency resources into utility, State, and regional plans; and

"(B) adopt policies establishing cost-effective energy efficiency as a priority resource.

"(17) RATE DESIGN MODIFICATIONS TO PROMOTE ENERGY EFFICIENCY INVESTMENTS.—

"(A) IN GENERAL.—The rates allowed to be charged by any electric utility shall—

* "(i) align utility incentives with the delivery of cost-effective energy efficiency; and

"(ii) promote energy efficiency investments.

"(B) POLICY OPTIONS.—In complying with subparagraph (A), each State regulatory authority and each nonregulated utility shall consider—

* "(i) removing the throughput incentive and other regulatory and management disincentives to energy efficiency;

"(ii) providing utility incentives for the successful management of energy efficiency programs;

"(iii) including the impact on adoption of energy efficiency as 1 of the goals of retail rate design, recognizing that energy efficiency must be balanced with other objectives;

"(iv) adopting rate designs that encourage energy efficiency for each customer class;

"(v) allowing timely recovery of energy efficiency-related costs; and

"(vi) offering home energy audits, offering demand response programs, publicizing the financial and environmental benefits associated with making home energy efficiency improvements, and educating homeowners about all existing Federal and State incentives, including the availability of low-cost loans, that make energy efficiency improvements more affordable.".

(b) NATURAL GAS UTILITIES.—Section 303(b) of the Public Utility Regulatory Policies Act of 1978 (15 U.S.C. 3203(b)) is amended by adding at the end the following:

"(5) ENERGY EFFICIENCY.—Each natural gas utility shall—

"(A) integrate energy efficiency resources into the plans and planning processes of the natural gas utility; and

"(B) adopt policies that establish energy efficiency as a priority resource in the plans and planning processes of the natural gas utility.

"(6) RATE DESIGN MODIFICATIONS TO PROMOTE ENERGY EFFICIENCY INVESTMENTS.—

"(A) IN GENERAL.—The rates allowed to be charged by a natural gas utility shall align utility incentives with the deployment of cost-effective energy efficiency.

"(B) POLICY OPTIONS.—In complying with subparagraph (A), each State regulatory authority and each nonregulated utility shall consider—

"(i) separating fixed-cost revenue recovery from the volume of transportation or sales service provided to the customer;

"(ii) providing to utilities incentives for the successful management of energy efficiency programs, such as allowing utilities to retain a portion of the cost-reducing benefits accruing from the programs;

"(iii) promoting the impact on adoption of energy efficiency as 1 of the goals of retail rate design, recognizing that energy efficiency must be balanced with other objectives; and

"(iv) adopting rate designs that encourage energy efficiency for each customer class.

For purposes of applying the provisions of this subtitle to this paragraph, any reference in this subtitle to the date of enactment of this Act shall be treated as a reference to the date of enactment of this paragraph.".

(c) CONFORMING AMENDMENT.—Section 303(a) of the Public Utility Regulatory Policies Act of 1978 (15 U.S.C. 3203(a)) is amended by striking "and (4)" inserting "(4), (5), and (6)".

Subtitle E—Energy Efficiency and Conservation Block Grants

SEC. 541. DEFINITIONS. 42 U

In this subtitle:

(1) ELIGIBLE ENTITY.—The term "eligible entity" means—

(A) a State;

(B) an eligible unit of local government; and

(C) an Indian tribe.

(2) ELIGIBLE UNIT OF LOCAL GOVERNMENT.—The term "eligible unit of local government" means—

(A) an eligible unit of local government-alternative 1; and

(B) an eligible unit of local government-alternative 2.

(3)(A) ELIGIBLE UNIT OF LOCAL GOVERNMENT-ALTERNATIVE 1.—The term "eligible unit of local government-alternative 1" means—

(i) a city with a population—

(I) of at least 35,000; or

(II) that causes the city to be 1 of the 10 highest-populated cities of the State in which the city is located; and

(ii) a county with a population—

(I) of at least 200,000; or

(II) that causes the county to be 1 of the 10 highest-populated counties of the State in which the county is located.

(B) ELIGIBLE UNIT OF LOCAL GOVERNMENT-ALTERNATIVE 2.—The term "eligible unit of local government-alternative 2" means—

(i) a city with a population of at least 50,000; or

(ii) a county with a population of at least 200,000.

(4) INDIAN TRIBE.—The term "Indian tribe" has the meaning given the term in section 4 of the Indian Self-Determination and Education Assistance Act (25 U.S.C. 450b).

(5) PROGRAM.—The term "program" means the Energy Efficiency and Conservation Block Grant Program established under section 542(a).

(6) STATE.—The term "State" means—

(A) a State;

BEFORE THE

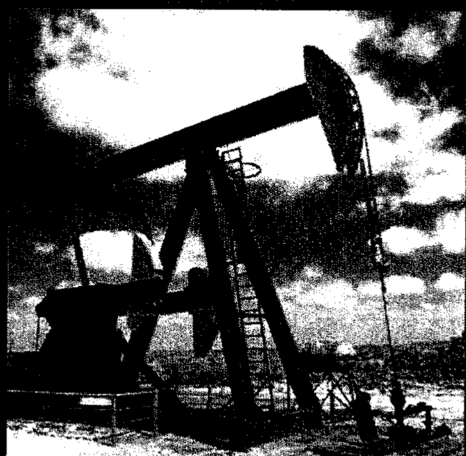
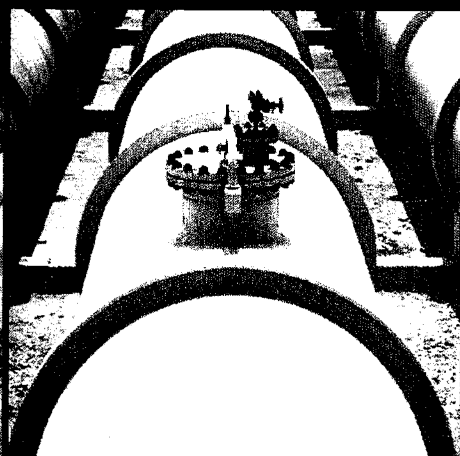
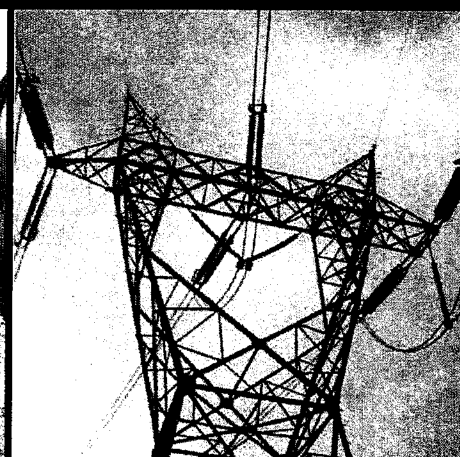
IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-09-28

IDAHO POWER COMPANY

ATTACHMENT NO. 5

Energy
Industry Research

November 18, 2009

KeyBanc
Capital Markets

Important disclosures for the companies mentioned in this report can be found at https://key.bluematrix.com/bluematrix/Disclosure.

KeyBanc Capital Markets Inc.,
Member NYSE/FINRA/SIPC

Table 11. Cost Recovery Mechanisms

	AMI / Smart Grid	Bad Debt / Uncollectibles	Distribution / Delivery Service Improvement / Reliability	DSM / Energy Efficiency / Conservation	Environmental	Fuel & Purchased Power	Pension / OPEB	Revenue Decoupling	Storm Damage	Stranded Costs	Transmission / RTO	CWIP in Rate Base Before Plant In-Service	New Construction
AEE		P[1]	X[1,2]	X	X[1]	X	X[1]						
AEP	X[1]		X[1,3]	X[1]	X[1]	X					X[1,4]	X[1]	G[1]
AVA						X		X[1]				X[1]	
CMS		X				X	F[1]	X		P			
CNL						X			X				
ED					X	X	X	X			X[5]		
DPL	F		P	X	X	X			X		X[4]		
DTE		X[1]		P	X	X		F	X	P	X[6]		
D	P[1]	X[1]	P[1]	X	X	X					X[4]		
DUK	X[1]	X[1]	X[1]	X[1]	X	X			X[1]		X[6]	X[1]	G
ETR				X[1]		X			X[1]				N
EXC	X	P[1]		X[1]	X[1]	X				X	X[1]	X[1]	
FPL				X	X	X			X			X[7]	N, W, S
FE		X[1]	X[1,3]	X[1]		X[1]			X[1]	X[1]	X[1,6]		
GXP				P[1]		X[1]					X[1]		
IDA	X[1]			X		X	F	X[1]					G
MDU						X		X[1]					
NI		X[1]		X[1]	X[1]	X	X[1]	F, X[1]					
NWE						X	X[1]						
PPL	P	X		P		X				X	X	X[8]	
POM	X[1]	F, X[1]	X[1]	X[1]	X[1]	X	F	F, X[1]		X[1]	X	X[8]	S
PNW				X	X	X					X		G[9]
PGN	X[13]			X	X[1]	X			P[1]		X[1]	X[1]	N
SO				X[1]	X	X			X			X[1]	N, G[10]
TE				X	X	X			X				
WEC					X	X					X[6,11]		
XEL				X[1]	X	X[1]		X[1]			X[6,12]	X[1]	W

Legend
F – filed by company for cost recovery treatment, regulatory acceptance and approval to be determined
P – plan, program or law approves cost recovery, but requires a separate plan filing or prudency review with regulators (usually outside of a general rate case)
X – active cost recovery mechanism, rate adjustment clause, rider, tracker, or specific rate provision
G, I, N, S, W – (G)eneral plant/pre-construction, (I)GCC, (N)uclear, (S)olar, (W)ind

Notes
1 Not in all jurisdictions
2 80% of costs recovered as fixed nonvolumetric monthly charge
3 Only recovers vegetation management costs
4 Recovers PJM-related costs
5 Recovers purchased power payments to NYISO
6 Recovers MISO-related costs
7 Florida allows small projects less than 0.5% of a utility's plant in service as component of rate base
8 FERC-granted transmission line projects
9 Line extension fees
10 Alabama new generating facilities and Mississippi new baseload capacity
11 Defer transmission costs exceeding amounts in rates and earn WACC return on unrecovered transmission cost deferrals.
12 PSCo retail Transmission Cost Adjustment (TCA) - allows for return on CWIP for transmission investments
13 Smart Grid recovery through the Energy Conservation Cost Recovery rider in Florida, DSM/EE rider in Carolinas

Sources: compiled from Company reports and SEC regulatory filings, KeyBanc Capital Markets Inc. research

September 10, 2009

SECURITIES

Equity Research

IDACORP, Inc.

IDA: Takeaways From Company Visit

Market Perform

Sector: Regulated Electric Utilities
Market Weight

Company Note

- **On 9/2, we visited with key members of IDA's mgmt, regulatory, and investor relations teams.** We came away from the meeting with increased comfort with Idaho's regulatory environment and IDA's long-term growth profile. Other topics of discussion included the impact of the economy on near-term sales, IDA's resource needs including Langley Gulch and major transmission projects and the company's Oregon-jurisdictional earnings profile.
- **Regulatory Progress Continues.** Having secured a number of positive regulatory changes in the past few years, IDA plans to forge ahead with additional enhancement proposals. Specific initiatives include the pursuit of a more forward looking test year, energy efficiency (EE) incentives and a pension tracking mechanism. IDA management expressed confidence in the regulatory acumen of the current Commission and pointed to the recent approval IDA's certificate of public convenience and necessity for the Langley Gulch Plant as a positive data point.
- **EPS Outlook.** Our 2009-2011 EPS estimates are $2.35, $2.45 and $2.55, respectively versus our previous estimates of $2.45, $2.50 and $2.55. We expect near-term EPS growth to be driven by both rate base growth and improved earned ROEs in both Idaho and Oregon.
- **Financing Needs.** We expect 2009 and 2010 financing needs will be satisfied with debt, internally generated funds and modest amounts of equity via IDA's dividend reinvestment and employee related plans. We believe the company will need to issue equity in 2011 as spending on the Langley Gulch plant continues to ramp. Overall, we view IDA's financing needs as manageable and are comfortable with the company's liquidity position and balance sheet.
- **Reiterate Market Perform Rating.** While we are attracted to IDA's service territory and rate base growth opportunities, valuation considerations keep us on the sidelines. With that being said, we continue to be encouraged with positive changes to IDA's regulatory principles, which has been an area of significant concern in the past. As a result, we would consider a more positive stance towards shares should valuation become more attractive.

	2008A	2009E		2010E	
EPS		**Curr.**	**Prior**	**Curr.**	**Prior**
Q1 (Mar.)	$0.48	$0.40 A	NC	NE	
Q2 (June)	0.39	0.58 A	NC	NE	
Q3 (Sep.)	1.14	1.11	NC	NE	
Q4 (Dec.)	0.16	**0.26**	**0.35**	NE	
FY	$2.17	**$2.35**	**2.45**	**$2.45**	**2.50**
CY	$2.17	$2.35		$2.45	
FY P/E	13.1x	12.1x		11.6x	
Rev.(MM)	$960	$984		$1,026	

Source: Company Data, Wells Fargo Securities, LLC estimates, and Reuters
NA = Not Available, NC = No Change, NE = No Estimate, NM = Not Meaningful

Ticker	IDA
Price (09/10/2009)	$28.37
52-Week Range:	$20-34
Shares Outstanding: (MM)	47.3
Market Cap.: (MM)	$1,341.9
S&P 500:	1,043.35
Avg. Daily Vol.:	196,368
Dividend/Yield:	$1.20/4.2%
LT Debt: (MM)	$1,283.6
LT Debt/Total Cap.:	46.2%
ROE:	9.0%
3-5 Yr. Est. Growth Rate:	5.0%
CY 2009 Est. P/E-to-Growth:	2.4x
Last Reporting Date:	08/06/2009 *Before Open*

Source: Company Data, Wells Fargo Securities, LLC estimates, and Reuters

Valuation Range: $29.00 to $30.00 from $27.00 to $29.00
We value IDA under P/E multiple (apply an 12.0-12.5X multiple to our 10E EPS of $2.45) and dividend discount analysis. Risks to our valuation include project delays or cancellations and consistently below average hydroelectric conditions.

Investment Thesis:
We are attracted to Idaho's service territory and strong rate base growth potential, and are encouraged by recent regulatory improvements. Our neutral rating largely reflects valuation considerations.

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Please see page 12 for rating definitions, important disclosures and required analyst certifications

on the investment, it would provide the company an opportunity to glean financial benefits from its EE investment.

- **Pension Tracking Mechanism.** IDA indicated that it is exploring a pension tracking mechanism as a means to improve the timeliness of pension cost recovery. Recall that per a June 1, 2007, Idaho PUC order, IDA's accounting for pension expense shifted from accrual-based to cash-based. Under the cash-based method, Idaho Power is allowed to defer, as a regulatory asset, non-cash expense for future recovery from customers when the company makes actual cash contributions. As a result, the earnings impact of pension expense is not an issue for IDA as it is for a number of other electric utilities seeking pension tracking mechanisms. IDA is merely exploring the idea as an enhancement that would allow the company more timely recovery. As a result, if IDA decided to pursue the pension tracker we would view its adoption favorably, but note that it will not likely impact our near-term EPS estimates.

- **Langley Gulch Decision.** On September 1, the Idaho Public Utilities Commission (IPUC) approved Idaho Power's request for a certificate of public convenience and necessity for the 300 MW combined-cycle Langley Gulch power plant. Consistent with Idaho legislation passed in April 2009, the approval included cost recovery assurance for at least $396.6 million, which represents the known and measurable portions of the total $427mm cost estimate. The $396.6 million is not a cap, however, and we expect Idaho Power will be able to recovery and earn a return on all just and reasonable costs. The ROE earned on the investment will be consistent with the commission-approved ROE at the time the plant goes into service.

  The IPUC did not approve inclusion of construction work in progress (CWIP) in rate base, but left the door open for CWIP recovery later in the project's life. We expect Idaho Power to file for CWIP as construction progresses.

  We are encouraged by the Commission's decision to approve ratemaking principles on the proposed plant and to consider the company's CWIP request at a later date. It is our understanding that the company's request faced stiff opposition by a number of industrial, irrigation and environmental parties who were requesting a ten month stay on the decision in light of load growth uncertainty. The IPUC's decision appears pragmatic and generally supportive of the company's plan. We consider this to be an incrementally positive data point on the Idaho regulatory environment.

- **Transmission Projects.** It appears that the approval of Langley Gulch may afford IDA some additional flexibility in the pursuit of two major transmission projects: Gateway West and Boardman to Hemingway. The 300 MW gas plant, which is scheduled for completion in 2012, will serve existing and future demand thereby alleviating any urgency assigned to the transmission projects. We also found it interesting that the Gateway West Project is not necessarily all or nothing. Some portions of the line are designed to fill system needs and would likely be built under any circumstances, while other portions are driven by outside requests which could be scaled back in light of economic conditions. With shares trading near book value and likely Langley-related equity needs and capital market uncertainty, we view flexibility on the timing and scale of the transmission projects favorably.

  Also, while we typically favor transmission investment, management confirmed that the projects would likely be state- rather than FERC-jurisdictional because they serve local needs. We consider FERC regulation to be more favorable than IPUC regulation as the FERC provides for more incentives and/or mechanisms to compensate for the risk of undertaking large multi-state transmission projects. As such, likely state regulation is an incremental negative relative to many peers that are developing FERC-regulated projects and reinforces our previous comments regarding our favorable view of the flexibility around timing and/or potential to scale back plans.

- **Sales Update and Post Recession Growth Profile.** Retail sales volumes declined 6% in the first half of 2009 including an 8% drop in the second quarter. While the first half sales numbers are clouded by unfavorable weather and poor sales to irrigation customers due to a material increase in precipitation, recessionary pressures are also contributing to the sales declines. Of note, residential and small general service customers are covered under the Fixed Cost Adjustment (FCA) mechanism, which mitigates the financial impact of sales declines - the FCA mechanism is running on a pilot basis through 2009. Industrial sales were down 9% in the second quarter and 6% in the first six months of 2009 driven, in part, by the scaling down of operations, including layoffs at Micron Technology.

  Management also addressed concerns related to its agreement with new customer Hoku to provide electric service to the company's polysilicon production facility in Pocatello, Idaho, in light of an amended electric service agreement (ESA) delaying the start date and reducing the levels of power in the ESA. Management

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INDUSTRY | COMMENT

MARCH 16, 2009

Regulatory Structure is crucial for utilities during tough economic times

Positive for companies with decoupling and fuel/power pass-through

During turbulent economic periods, the importance of favorable regulatory relationships and productive regulatory structures cannot be ignored. Although as a group utilities are generally considered to be lower risk stocks, upon closer examination the sometimes vast differences in regulatory frameworks set the companies apart within the sector. The two most relevant regulatory mechanisms are decoupling, which separates electricity usage from revenues, and fuel/power pass through clauses which limit or eliminate commodity risk. The ideal model during this economic cycle is a decoupled utility with a 100% fuel/power pass through clause. These mechanisms insulate utilities from reductions in demand and volatile, although presently low, commodity prices.

California is King: Good for PCG, SRE, EIX

The California utility framework supports financially healthy utilities. The state is decoupled and has an automatic fuel/power clause that is adjusted monthly, barring rare swings of 5% or greater. In California, PCG is the only pure-play utility, whereas roughly half of SRE and EIX's earnings are derived from CA utility operations.

Wires and Pipes (CNP, UTL): Insulated from commodities, exposed to usage declines

CNP and UTL do not assume commodity risk, but both companies are currently at risk of lower revenues from lower demand. Decoupling is approved for UTL in MA and pending in NH and ME. For CNP, in TX a high fixed-cost charge somewhat offsets the need for decoupling.

Middle of the road: NVE, TE, DUK

These companies each have traditional fuel/power pass-through clauses in their respective operating states and each has strong histories of favorable treatment in these proceedings. There is, however, an element of risk beyond that of CA since adjustments are not automatic. DUK has decoupling in OH for gas. NVE and TE do not have decoupling.

Uncertainty/Room for Improvement: AYE, BKH, IDA, PNM

Each of these companies recently underwent regulatory changes in some manner, creating uncertainty in terms of how the changes will affect the companies. All now have fuel/power protection to some degree, but mechanisms differ and fall short of CA's automatic recovery system. IDA is decoupled through a pilot program in ID, but the other companies are not.

Priced as of prior trading day's market close, EST (unless otherwise noted).
All values in USD unless otherwise noted.
For Required Disclosures, please see Page 6.

weakness or weather. Accordingly, we would view the Save-a-Watt program as falling short of the full downside protection accorded by standard decoupling. To date, the program has been approved in OH and is pending in the other jurisdictions.

Table 2. DUK Fuel/Power clause true-up schedule

	NC	SC	OH - Gas	OH-Electric	IN	KY
True-up frequency	Annual	Annual	Monthly	Quarterly	Quarterly	Monthly

Source: RBC Capital Markets and Company Data

NVE: Average traditional structure

Nevada, California

In NV the company has a fuel and purchased power pass-through mechanism under which the company submits true-up filings every quarter. Although there is always a risk that regulators will not approve increased costs, the NVE Energy has a strong history of receiving fair treatment in these proceedings. Regulators understand that commodity risk should be absorbed by the consumers. There is currently no decoupling in NV.

NVE Energy has a small group of customers in the Lake Tahoe area of CA. For details, see the CA description for PCG, EIX and SRE above.

TE: Average traditional structure

Florida

TE has a traditional fuel and purchased power pass-through clause that is regulated by annual true-up filings. As NVE in NV, TE has a strong history of favorable outcomes from these true-up filings. Furthermore, TE does not have a large power gap which minimizes the affect of power prices on the business. There is no decoupling in FL.

IDA: Average traditional structure, but regulatory disconnect remains

Idaho, Oregon

In ID there is a traditional power cost adjustment, which includes fuel and purchased power, that is trued-up annually. Differences between the actual and forecasted costs are split 95/5 between customers and shareholders, recently increased from 90/10 sharing. The sharing mechanism provides a shareholder benefit when hydrology is above normal, but we would prefer that 100% of the risk/reward go to the consumers. Hydrology has been below normal more often than not in the last 10 years.

IDA is in the midst of a three-year decoupling pilot program which has been favorably received. We believe that the fixed cost adjustment mechanism will become a permanent part of the regulatory framework and consider the company to be decoupled in ID. *

IDA has a small customer base in OR which recently approved a fuel and purchased power clause. This clause is regulated by annual true-ups.

BKH: Unfavorable due to uncertainty of unchartered waters

South Dakota, Wyoming, Colorado, Montana, Nebraska, Iowa, Kansas

Prior to the 2008 acquisition of the Aquila utilities, BKH had operated in SD, WY, and MT. With the Aquila acquisition, the company added operations in CO, NE, IA, and KS. Although full-year results for the new assets have not been recorded, we estimate that a little over half of BKH's earnings are now subject to new regulatory environments. Accordingly, this adds an element of regulatory uncertainty which is unfavorable in the current risk-averse market.

South Dakota (Electric): Traditional, Less than 100% pass-through

Transmission and steam plant fuel adjustments are passed through to customers based on actual costs incurred, on an annual basis. There is also a conditional energy cost adjustment, relating to purchased power and natural gas for generation purposes, in which BKH Power absorbs the first $2MM of increased costs, or $1MM of the savings. Beyond these thresholds, the additional costs or refunds are passed through by way of annual filings.

Wyoming (Electric): Traditional, Less than 100% pass-through

Cheyenne Light has a pass-through mechanism for transmission, fuel, and purchased power, subject to a $1MM threshold. For amounts exceeding this threshold, BKH passes along or collects 95% of the excess amount to consumers and shareholders absorb the remainder.

Colorado (Electric and Gas): Traditional

The company has a cost adjustment mechanism for purchased power and fuel (through direct recovery or credits issued), and transmission (through a rider to customer bills).