

# Electrical Power in Idaho

Idaho residents consistently enjoy some of the least expensive electric service in the nation, according to surveys conducted by the National Association of Regulatory Utility Commissioners (NARUC), the Edison Electric Institute and the Energy Information Administration of the U.S. Department of Energy.



## **Idaho Power Company**

**2005 Average Number of Customers/Avg. Revenue/kwh**

*(Computed from data available in FERC Form 1 Annual Reports)*

**360,484 Residential Customers/\$0.0633**

**69,642 Commercial Customers/\$0.0486**

**121 Industrial Customers/\$0.0353**



## **Avista Utilities**

**2004 Average Number of Customers/Avg. Revenue/kwh**

*(Computed from data available in FERC Form 1 Annual Reports)*

**96,838 Residential Customers/\$0.0647**

**15,426 Commercial Customers/\$0.0653**

**502 Industrial Customers/\$0.0414**



**2004 Average Number of Customers/Avg. Revenue/kwh**

*(Computed from data available in FERC Form 1 Annual Reports)*

## **PacifiCorp/Rocky Mountain Power**

**51,314 Residential Customers/\$0.0408**

**7,228 Commercial Customer/\$0.0601**

**5,436 Industrial Customer/\$0.0345**

# Rate adjustments

A good water year and softening wholesale gas prices led to both electric and gas rate decreases for Idaho customers of major utilities during 2006

The commission approved a base rate increase for **Idaho Power Co.** customers of 3.2 percent. But combined with a decrease in the annual Power Cost Adjustment of about 16 percent and the expiration of a 2.2 percent tax adjustment, overall rates for Idaho Power decreased by 14 percent. A softening wholesale gas market, nearly fully recovered from Gulf Coast hurricanes in 2005, resulted in a 3.8 percent decrease in the Purchased Gas Cost Adjustment (PGA) for customers of **Intermountain Gas** (see page 40) and a 3.4 percent decrease for **Avista Gas** customers (see page 42).

Idaho Power rate case first in memory to be settled  
Case No. IPC-E-05-28, Order No. 30035

On Oct. 28, 2005, Idaho Power asked the commission to approve a 7.8 percent increase in base rates. Parties to the case, including commission staff, the Industrial Customers of Idaho Power, the Idaho Irrigation Pumps Association and several contract customers, entered into settlement negotiations. On Feb. 27, 2006, the parties proposed a settlement for a 3.2 percent base rate increase and an \$18.1 million increase in annual revenue. The company originally sought a \$44 million increase in annual revenue.

The commissioners commended the parties who “were able to compromise and settle the disputed issues in this case.” Commissioners noted that this is the first instance in their recollection of an Idaho Power rate case being settled.

These are the major components of the settlement:

- The 3.2 base rate increase applies to all major customer classes, although the parties agreed that the company’s model used to determine the cost of service to each customer class does not create a precedent for any future rate case and the parties’ decision not to object to that model does not preclude an objection to it in a future rate case.
- The rate of return is 8.1 percent. The company originally requested 8.42 percent. The parties did not set a return on common equity. The company proposed an ROE in the range of 11 to 12 percent.
- The monthly service charge for residential and small commercial customers is increased from \$3.30 per month to \$4. Idaho Power originally requested an increase to \$6. Idaho Power agreed to not file for an increase in the service charge for at least two years.
- At the request of irrigation customers, Idaho Power agreed to convene a working group to review the current operations and results of the Irrigation Peak Rewards program. (The case, IPC-E-06-22), was filed in September and final order issued on Nov. 30, Order No. 30194. Changes to the program included an increase in demand credits for irrigators and a reduction in the horsepower limit to make irrigators using pumps rates at 75 hp (rather than the former 100 hp or higher) eligible for the program.

Finally -- a wet year! Customers benefit from record PCA reduction  
Case No. IPC-E-06-07, Order No. 30047

Two weeks after the rate case order, Idaho Power filed its annual Power Cost Adjustment. Before the 2006 PCA, customers were paying about 0.6 cents per kWh surcharge for the PCA. After June 1, the PCA was reduced to a credit that subtracts 0.3689 cents per kWh from the base rate. The overall (base and PCA credit) non-summer rate decreased from 6.02 cents per kWh to 5.05 cents, almost a full cent reduction. The summer rate decreased even further, from 6.69 cents to 5.73 cents per kWh. The reduction for commercial customers was 14.82 percent and 25.67 percent for industrial customers.

***What is the power cost surcharge (PCA)?***

Customer rates are divided into two components, the base rate and the power cost adjustment or PCA. (In the case of gas utilities, this same mechanism is called the “purchased gas cost adjustment” or PGA.) The normal costs for supplying power are recovered in the utility’s base rates. However, a utility may incur higher than normal costs from unusual circumstances, such as low water conditions or higher than anticipated market conditions. The PCA annually increases (through a one-year surcharge) or decreases (with a credit) customer rates to account for above-normal or below-normal power supply costs. Yearly PCA adjustments, up or down, do not affect the utility’s earnings. The money collected from the PCA is essentially a pass-through, passing directly from the utility to its power suppliers.

***Simpler definition:*** The base rate includes the cost of everyday operations. The power cost adjustment includes the variable costs of energy.

Irrigation customers saw about an 18 percent reduction in their overall rate.

During 2006, with Snake River streamflows at 33 percent above the 30-year average, Idaho Power’s annual power costs decreased by \$123 million, which is \$46.8 million below base rates. As the PCA mechanism requires, 90 percent of that \$123 million is credited back to customers and the other 10 percent to shareholders.

This year’s PCA represents the largest credit for customers since the mechanism was put in place in 1993. It is also the first time, after six years of drought conditions, that customers received a credit rather than being assessed a surcharge.

Avista base rates, PCA both stable

Case No. AVU-E-06-08, Order No. 30166; AVU-E-06-09, Order No. 30164; Case No. AVU-E-06-05, Order No. 30161

Residential customers of Avista Utilities received an approximate a 91-cent per month increase in electric bills due to the expiration of a rate credit and about a 47-cent per month decrease due to an increase in Bonneville Power Administration’s residential exchange credit. Both adjustments became effective Nov. 1.

***What is the Bonneville Power Administration?***

The Bonneville Power Administration is a federally owned wholesale power marketer, selling electricity at cost to customers in four Northwestern states, including Idaho. The electricity is generated from a number of hydroelectric facilities along the Columbia River and its tributaries.

The expiration of a credit given to customers from the sale of the Centralia and Skookumchuck power plants resulted in an increase to average residential bills of about 1.45 percent. A second adjustment, an increase in the Bonneville Power Administration (BPA) credit, reduced average residential bills by about 0.75 percent.

When Avista sold its share of the Centralia, Wash., power plant, customers were allowed to share in about \$7.5 million of the company's net-of-tax gain. That credit was fully refunded to customers by Nov. 1, requiring its removal. Added to the credit in 2004, was \$154,000 from the sale of the Skookumchuck hydroelectric generation facility, which supplied cooling water to the Centralia Power Plant.

While the Centralia credit expired, another credit, the BPA credit, increased.

The Northwest Power Act of 1980 requires that residential and small-farm electric customers share in the benefits of the hydropower system, typically through a credit on their electric bills. The second half of a 10-year agreement (2001-2011) between Avista and BPA allows for increased benefits to Avista customers. The credit increases from \$4.12 per month to \$4.59 per month for a customer who uses 1,000 kilowatt-hours per month.

Avista's Power Cost Adjustment (PCA) was continued for another year at the same level, but must be reviewed before it can be renewed again, the commission ruled.

The Idaho Public Utilities Commission approved Avista's application for a 12-month extension of the 2.45 percent PCA surcharge, but expressed concern the surcharge is being continued to allow for projected future power supply expenses rather than recovering only those costs directly attributable to the Western energy crisis of 2000-01, the reason the surcharge was created.

Extension of the surcharge does not increase rates. It leaves the surcharge – about 0.163 cents per kWh for residential customers – in place for another year. Revenues from the surcharge do not increase Avista's earnings. The surcharge is expected to raise about \$4,268,000, which goes directly to pay debts Avista owes its power suppliers.

The surcharge, originally at 19.4 percent, was implemented in October 2001 to allow the company to start paying down a \$78 million debt it incurred following the 2000-01 Western states' energy crisis. In 2005, with the debt down to \$26.1 million, the surcharge was reduced to 4.38 percent. In April of this year, the surcharge was reduced to its current level of 2.45 percent.

By June 30 of this year, the deferred balance was down to \$1.5 million. But increased expenses that Avista claims are due to a shortfall in hydro generation and to increasing gas fuel expenses for the utility's thermal generating plants, resulted in the deferral balance increasing to \$3.2 million by July 31. The company anticipated that by fall, the balance would have grown beyond the \$4.3 million in annual revenue the surcharge collects.

The commission said further study of the original intent of the surcharge and future methods for treating extraordinary power supply expense are warranted before the surcharge can be renewed again. "We find that the events that justified implementation of changes in PCA methodology, however, cannot be used to support an unending continuation of the charges," the commission said. "A thorough review and examination is required."

In the company's current PCA filing, it uses a projected increase, rather than an actual increase, in power

supply expense to justify its request to continue the existing surcharge level. "This recommended use of projections is a significant departure from the approved PCA methodology," the commission said.

The commission ordered the company and commission staff to conduct workshops to examine future treatment of extraordinary power supply expense. Avista must file a report filed with the commission by on or before August 15, 2007.

## PacifiCorp, major parties reach rate settlement

Case Nos. PAC-E-06-04 (Order No. 30199) PAC-E-06-08 (Order No. 30196) PAC-E-06-09 (Order No. 30197)

The Idaho Public Utilities Commission in late December approved a settlement agreement between PacifiCorp and major customer groups that will increase revenue to the company by \$8.25 million annually, or 5.1 percent. The agreement does not impact residential rates. The only customers to get an increase will be irrigation customers (5 percent) and two industrial customers, Monsanto Company (16.5 percent) and Agrium, also known as Nu-West Industries, (4 percent).

PacifiCorp, which operates in eastern Idaho as Rocky Mountain Power (formerly Utah Power & Light), serves about 64,000 Idaho customers.

The Idaho Irrigation Pumpers Association, Monsanto and Agrium, all agreed to the settlement. Rate increases for irrigators and Monsanto are effective Jan. 1, 2007. Agrium rates, by an earlier commission order, became effective Sept. 1, 2006.

The settlement prevented the need for PacifiCorp to file a full rate case before the commission. The commission commended PacifiCorp and all the parties for reaching the agreement. "We acknowledge that the stipulation ... represents a compromise of party positions," the commission said.

Irrigators will pay 5 percent more, increasing revenue for that class by \$1.7 million. However, if irrigators volunteer to participate in the company's Irrigation Load Control Credit Rider Program, they will receive a refund after the end of the 2007 irrigation season. Counting the refund, which totals \$450,000, the net average increase to irrigators is 3.7 percent. The increase to irrigators moves them \$1.7 million closer to the approximate \$3.7 million in additional revenue the company claims is required for the irrigation class to attain full cost of service.

Rates for Monsanto, PacifiCorp's largest customer in its six-state area, increase by 16.5 percent, raising \$6.8 million. Monsanto, which operates an elemental phosphorous plant near Soda Springs, comprises about 43 percent of PacifiCorp's electrical requirement in Idaho. Electricity amounts to about one-third of Monsanto's total production cost.

A significant change in the Monsanto rate is the agreement by Monsanto to move from a contract customer to a tariff customer. That means, as a tariff customer, Monsanto rate changes will take place simultaneously with rate changes for other customer classes. Under the current contract, which expires Dec. 31, rates for Monsanto would change only when a new contract was negotiated.

Monsanto also agreed to an increase in the number of hours PacifiCorp can interrupt or curtail service to Monsanto in order to meet demands on other sectors of PacifiCorp's six-state service territory. The hours service can be interrupted will be 1,000 annually compared to the previous 800 hours. Monsanto agreed to increase the hours of interruption to offset what would have been a more substantial increase to its rates as a result of a PacifiCorp cost-of-service study that concluded the revenue raised from Monsanto was about \$13 million under cost to serve it. The 16.5 percent increase in rates moves Monsanto \$6.8 million closer, or more than half way, to full cost of service.

The 4 percent increase for Agrium moves it \$150,000 closer to the \$428,000 PacifiCorp claims is needed to serve that customer. Agrium produces phosphate fertilizer at facilities also near Soda Springs.

As part of the settlement, the Community Action Partnership of Idaho (CAPAI) agreed not to object to PacifiCorp's rate application if PacifiCorp also agreed to initiate a proceeding before the commission to significantly increase the company's contribution to low-income weatherization programs. CAPAI is a non-profit corporation consisting of six community action agencies that fight poverty. The commission is now considering, under a separate docket (PAC-E-06-10), whether the company's policy of funding only 50 percent of weatherization costs for low-income customers is reasonable.

PacifiCorp also agreed to a one-time \$10,000 contribution from shareholder money to two community action agencies in eastern and southeastern Idaho to be used for the Lend-a-Hand program during the 2006-07 heating season. PacifiCorp further agreed to support legislation sponsored by CAPAI that would give the Public Utilities Commission authority to approve utility-proposed low-income assistance programs.

# Acquisition, reorganization

MidAmerican acquisition of PacifiCorp approved  
Case No. PAC-E-05-08, Order No. 29973

MidAmerican Energy Holdings Company's bid to acquire PacifiCorp, which does business in southeastern Idaho as Rocky Mountain Power, was approved by the Idaho Public Utilities Commission in February.



MidAmerican is a privately held Iowa corporation engaged primarily in the production and delivery of energy from a variety of fuel sources including coal, natural gas, geothermal, hydroelectric, nuclear, wind and biomass. MidAmerican's principal owner is Berkshire Hathaway, Inc, headed by billionaire investor Warren Buffett.

Idaho was the third of six states to approve the acquisition before it became final. Before the acquisition, PacifiCorp was a wholly owned subsidiary of ScottishPower. Under the acquisition, PacifiCorp becomes an indirect, wholly owned subsidiary of MidAmerican, retaining its name and headquarters in Portland. ScottishPower sold all of its PacifiCorp common stock, valued at \$9.4 billion, to MidAmerican. That includes \$5.1 billion in cash and about \$4.3 billion in net debt and preferred stock.

The acquisition is in the public interest, commissioners said, because of MidAmerican's desire to invest at least \$1 billion per year for the next five years in transmission and generation upgrades, its long-term commitment to the utility business, its commitment to maintain or improve upon PacifiCorp's customer service standards and its promise that rates will not increase as a result of the acquisition. Rates will not increase for PacifiCorp's 60,000 customers in southeastern Idaho as a direct result of the acquisition.

The commission said there was no opposition from the public or intervening parties during the course of the commission's seven-month analysis of the case. "This is our third merger-acquisition concerning Utah Power & Light and the least contentious," the commission said. ScottishPower merged with PacifiCorp in 1999.

As part of the acquisition, MidAmerican agreed to abide by 52 commitments that apply to all six states in PacifiCorp's territory and another 36 commitments specific to Idaho. One of the Idaho commitments grants Idaho customers \$640,000 in rate credits in each of 2006 and 2007. Another requires PacifiCorp to maintain its dedicated irrigation specialist in eastern Idaho. Another Idaho condition requires PacifiCorp to establish a process to address the technical, economic and planning issues associated with the development of integrated gasification combined cycle (IGCC) technology. IGCC plants convert coal into a gas and then burn it, significantly reducing greenhouse gas emissions.

Another commitment requires that none of the acquisition costs be included in PacifiCorp rates without commission approval.

The agreement also includes, "ring-fencing provisions" which will isolate the credit risks of PacifiCorp from the credit risks of MidAmerican or any of its subsidiaries. PacifiCorp will maintain its own accounting system, maintain separate debt and its own credit rating. MidAmerican and PacifiCorp will provide the commission access to all books of accounts as well as documents and records of MidAmerican's affiliates. Neither PacifiCorp, nor its subsidiaries will, without commission approval, make loans or transfer funds to MidAmerican or its affiliates or assume MidAmerican's obligations or liabilities.

The commission also liked the fact that MidAmerican intends to own PacifiCorp for the long term, leading to stability in ownership and investment in infrastructure. MidAmerican is uniquely suited to make sizeable investment because it is privately held and, therefore, not subject to shareholder expectations of regular, quarterly dividends and a fast return on investments. The PacifiCorp cost of debt under MidAmerican, due to its association with Berkshire Hathaway, should be significantly reduced, saving customers about \$6.3 million over the next five years. Historically, MidAmerican's utility subsidiaries have been able to issue long-term debt at levels below their peers with similar credit ratings.

MidAmerican and PacifiCorp commit to contribute \$40,000 annually for low-income bill payment assistance to Idaho customers for a five-year period beginning July 1 this year. MidAmerican will also provide shareholder funds of up to \$66,000 to hire a consultant to study and then design a possible "arrearage management project" with goals of reducing service terminations, reducing referral of delinquent customers to third-party collection agencies, reducing collection litigation and increasing voluntary customer payment plans.

The commission's order approves a settlement agreement reached by parties in the case including commission staff; PacifiCorp; MidAmerican; J.R. Simplot Co.; Monsanto Co.; the Idaho Irrigation Pumpers Association and the Community Action Partnership of Idaho, which represents low-income customers. The International Brotherhood of Electrical Workers and Idaho Power Co. did not sign the settlement but do not oppose it.

### Avista creates holding company

Case No. AVU-E-06-01 and AVU-G-06-01; Order No. 30091

The Idaho Public Utilities Commission approved Avista Corporation's application to conduct a corporate reorganization and form a holding company to be known as AVA Formation Corp.

Under the reorganization, AVA Formation Corp. becomes the parent company of Avista Utilities, which, in northern Idaho, serves about 110,000 electric customers and 65,000 natural gas customers. The majority of the Spokane-based utility's customers are in Washington state.

The commission agreed with findings of its staff that the reorganization should reduce financial risk for the utility and improve its credit ratings.

The repeal of the Public Utilities Holding Company Act of 1935, often referred to as PUHCA, allows utilities that operate in multi-state jurisdictions to form holding companies. The holding company structure will provide additional protection for ratepayers by further separating the regulated utility's operations from the operations of other Avista subsidiaries that are not regulated. The protections, referred to as "ring fencing," are designed to ensure that ratepayers dollars are not used to subsidize unregulated subsidiaries of Avista and that ratepayers are protected from the risks of Avista operating other non-regulated businesses.

Avista stated in its application that the reorganization does not include the transfer of utility assets and that Avista customers will not see any change in the utility or its operations. Avista Utilities will continue to be subject to the Idaho Public Utilities Commission on matters impacting its Idaho customers such as rates and customer service.

Commission staff said that a number of commitments in the stipulation between staff and Avista address the need for ring-fencing around Avista Utilities, which will prevent the utility arm of the business from being pulled into a parent corporation bankruptcy proceeding. Those provisions include the maintaining of separate books and records for each Avista entity as well as granting commission staff full access to books and documents pertaining to the regulated utility side as well as those of the unregulated Avista affiliates and parent corporation. Both the parent corporation and Avista Utilities will be required to report to staff and request commission approval when certain events occur, such as procurement of loans, the spin-off of any entity, the dissolution of business activities, dividend payment arrangements and changes in the credit ratings of each agency.

Another commitment prohibits Avista Utilities from making any dividend payments to the parent corporation that would reduce Avista Utilities' common equity capital below 25 percent of its total adjusted capital without commission approval.

Utilities allowed to defer some expense from failed Grid West effort  
Case Nos. AVU-E-06-03, Order No. 30151; IPC-E-06-06, Order No. 30157; PAC-E-06-03, Order No. 30156

Idaho's three major regulated utilities will be allowed to defer costs they incurred in attempting to form a regional transmission organization that ultimately was not created. The expenses were in the form of loans made to the transmission organization called Grid West.

Establishment of the deferred accounts does not immediately impact customer rates. The commission will determine the prudence of the expenses when each of the three regulated utilities files its next rate case.

The commission denied the utilities' request that they also be allowed to recover interest that would accrue on the deferred accounts. And the commission denied Idaho Power's request to defer about \$2.6 million in internal business expenses associated with the Grid West effort. ***(Idaho Power later petitioned the Commission for reconsideration on the part of its order that denied the utility carrying costs of about \$191,000 on the deferral of Grid West expenses. The commission granted Idaho Power's petition***

*and, at the filing of this report, was waiting for more comments to be filed by Idaho Power.)*

In response to orders issued by the Federal Energy Regulatory Commission (FERC), utilities in the Pacific Northwest were told to develop an independent transmission operator, or Regional Transmission Organization (RTO). RTOs are designed to enable open and competitive wholesale electric markets so that potential competitors have the same access to regional transmission grids as do established utilities.

Grid West was proposed to serve as a non-profit, independent transmission operator to manage and control transmission in Washington, Oregon, Idaho, Nevada, Utah and parts of Montana, Wyoming and California. The Bonneville Power Administration, which dominates ownership of high-voltage transmission lines in the Northwest, decided to withdraw from the Grid West effort. PacifiCorp, after being acquired by MidAmerican Energy Holdings Company, also withdrew due to concern over costs, transmission operations and other issues. Several utilities expressed concerns that Grid West would mirror the experience of RTOs in other regions of the country, which have experienced higher than anticipated operational costs.

Idaho Power sought a total deferral in its Idaho jurisdiction of \$3.35 million. Of that, the commission agreed to allow the utility to defer about \$1,077,090. About 14 percent of that deferral will be allocated the utility's Oregon customers. The \$1.077 million excludes about \$197,000 in interest accrued through March 31 on loans the company made to Grid West. The loans ceased to accrue interest after that date. Idaho Power will be allowed to amortize the deferral over a five-year period beginning Jan. 1, 2007.

Avista, which has a much smaller customer base in Idaho, loaned Grid West about \$1.2 million, including \$421,620 allocated to its Idaho jurisdiction. The commission allowed deferral of \$356,450 in Idaho after removing interest. Avista will also begin amortization on Jan 1, 2007 over a five-year period.

**What happens now that Grid West has failed?**

Two new groups of transmission owners and interested stakeholders have recently begun to address the efficiency, reliability, planning, and expansion of the Pacific Northwest's electricity transmission grid.

**ColumbiaGrid**, a non-profit membership corporation with a footprint covering Washington, Oregon, and northern Idaho, formed in March 2006 with the following members: Avista, Bonneville Power Administration, Chelan County Public Utility District, Grant County Public Utility District, Puget Sound Energy, Seattle City Light and Tacoma Power. ColumbiaGrid will operate through Functional Agreements entered into by its members and interested non-members. The board approved the first agreement, Planning and Expansion, in December 2006. Functional Agreements for reliability and for a common queue for transmission service requests are under development.

**The Northern Tier Transmission Group** consists of Idaho Power, Rocky Mountain Power/PacifiCorp, NorthWestern Energy, Deseret Power Electric Cooperative and Utah Associated Municipal Power Systems, with a footprint covering southern and central Idaho, Utah, Montana, Wyoming, Oregon and northern California. Northern Tier will address and coordinate regional transmission use and planning under working groups guided by a steering committee of transmission owner executives and state regulators. The group has already entered into an agreement to coordinate the sharing of regulation reserves and next will address how to bring openness and transparency to the regional transmission planning process.

In May 2006, the Federal Energy Regulatory Commission (FERC) issued a proposed rule to reform the Open Access Transmission Tariff required for all jurisdictional transmission owners. The purpose of this reform is to further competition and address the long-held goal of preventing discrimination in the provision of transmission service to both regulated utilities and to independent operators who want access to the grid. The final rule FERC issues in 2007 will have an impact on the transmission work conducted by both Columbia Grid and Northern Tier.

PacifiCorp, which does business as Rocky Mountain Power in southeastern Idaho, loaned \$2.7 million to Grid West. The commission authorized a deferral of \$174,000 for PacifiCorp's Idaho jurisdiction.

Even though the effort to form a regional transmission organization has not been successful to date, the commission said the utilities should be entitled to recovery of the amounts they loaned because they were compelled by the

Federal Energy Regulatory Commission to participate in the development of an RTO. Had the RTO been created, it would have acquired control of the region's transmission facilities and implemented a surcharge on transmission customers to repay the loans made by the utilities.

The commission agreed with the utilities' contention that customers did benefit from the RTO formation process.

Idaho Power said it gained experience in how an independent, regional transmission system operator would be created and how it would manage a regional transmission system. Avista Utilities, as a result of the RTO process, joined five other utilities to form a non-profit organization, ColumbiaGrid, to pursue improvements to ways in which the region's transmission providers operate and manage the system.

## Customers to benefit from 90 percent of emission allowance sales

Case No. IPC-E-05-26, Order No. 30041

The commission approved a negotiated settlement that grants Idaho Power customers 90 percent of the proceeds from Idaho Power's sale of emissions allowances. Customers would benefit with nearly \$70 million applied against the annual Power Cost Adjustment (PCA), beginning in the spring of 2007. The remaining 10 percent will be retained by the company as a shareholder benefit.

### **Why emission allowance sales?**

An amendment to the 1990 Clean Air Act establishes a national program for the reduction of acid rain. Scientists have determined that sulfur dioxide (SO<sub>2</sub>) and nitrogen oxide (NO<sub>x</sub>) are the primary causes of acid rain. In the United States, about two-thirds of all SO<sub>2</sub> and one-fourth of all NO<sub>x</sub> comes from thermal (coal and natural gas) electric generating plants.

The PCA tracks the company's above-normal or, as was the case during 2006, below-normal power supply costs. The PCA appears as a surcharge or credit on customer bills to account for changing streamflow and market conditions.

Idaho Power has sold 78,000 emissions allowances for about \$81.6 million. The negotiated settlement called for customers to receive about \$42.1 million, after taxes, but commission staff and the U.S. Department of Energy pointed that the after-tax credit to customers should be grossed-up to recognize the tax savings that will accrue when the credit is actually provided to customers through the PCA. That brought the customer allocation up to \$69,126,518.

In August, the commission granted Idaho Power Co. blanket authority to sell its surplus sulfur dioxide allowances. However, commission staff, Micron, and the Industrial Customers of Idaho Power were not

able to agree on how much of those sale proceeds should be shared with Idaho Power customers. After settlement negotiations, the parties were able to agree on a proposed settlement.

Under the federal program, thermal power plant owners are issued limited allowances for their plants' sulfur dioxide emissions based on a specific plant's past emissions and a nationwide cap placed on the total amount of SO<sub>2</sub> that can be emitted.

Each allowance authorizes the utility to emit one ton of SO<sub>2</sub>. At the end of each year, a utility generating unit must hold allowances equal to its allotted annual SO<sub>2</sub> emissions. A utility that holds over its annual requirement is considered to have surplus allowances that can be sold on the open market or through auctions sponsored by the Environmental Protection Agency.

Idaho Power has an ownership interest in three coal-fired plants: Jim Bridger in Wyoming, North Valmy in Nevada and Boardman in Oregon.

# Wind issues dominate 2006

As was the case during 2005, the increasing development of wind as an energy source posed new questions for the commission, regulated utilities and wind developers. Idaho Power, later joined by PacifiCorp and Avista, received and sought commission approval to suspend the company's federal obligation to buy wind power from independent developers of small wind projects to allow time to further examine a fair price for wind given its unpredictable output. The commission temporarily lowered the size of non-firm wind projects that can qualify for a published government rate from 10 megawatts to 100 kilowatts. (*See definition of PURPA rate at right.*) At the filing of this report, the commission was awaiting a study by Idaho Power Co. on the costs of integrating wind into its system.

## **What is PURPA?**

Congress passed the Public Utility Regulatory Policies Act during the energy crisis of the late 1970s. One of its stated goals is to encourage development of renewable energy technologies as alternatives to burning fossil fuels or constructing new power plants. The federal act requires that electric utilities offer to buy power produced by small power producers or co-generators who obtain Qualifying Facility (QF) status. The published rate to be paid project developers is set by state commissions and is to be equal to the cost the electric utility avoids if it would have had to generate the power itself or purchase it from another source.

The 100 kW limit does not apply to all PURPA contracts, but only wind contracts that are not "firm," meaning they cannot be backed up by an alternative energy source when wind fails to generate the amount of energy the wind

developer commits to deliver to the power company. To ensure system reliability, Idaho Power stated that intermittent wind resources must be "firmed" by backup power. An earlier company analysis concluded that in order to safely integrate 1,000 MW of intermittent wind generation, it would be necessary to concurrently add 640 MW of combustion turbines to provide capacity when wind resources were not operating. Idaho Power said the added cost of backup power should be included in the calculation of rates for wind. Wind developers argued that a performance band established by the commission in a 2004 case that penalizes wind producers for not falling within 90 to 110 percent of their projected output sufficiently deals with the firm vs. non-firm characteristics of wind.

But the questions over a fair rate for wind did not seem to curb wind development in the state. By mid-July 2006, the commission had approved 18 PURPA wind projects over 18 months. Combined, the projects will have the capacity to generate up to 246.8 megawatts once installed. Over the same 18 months, the state of Idaho witnessed a 66 percent increase in PURPA project capacity due almost entirely to the development of wind projects. Wind projects, when fully developed, will represent about 45 percent of the state's total 552.2 MW of PURPA capacity.

In addition to PURPA projects, Idaho utilities entered into negotiated wind agreements with independent developers of projects too large to qualify for the PURPA rate. These projects are selected primarily through a bid process. About 62.5 MW of wind have been added from the Wolverine Project, which sells to PacifiCorp in eastern Idaho. In July, Idaho Power Co. named Texas-based Horizon Wind Energy as the successful bidder for the development of a 66-MW wind project to be built in Union County, Ore., near North Powder. The project is expected to be online by the end of 2007.

## Utilities, wind generators argue over transmission costs

Case No. IPC-E-06-21

A complaint filed by Cassia Gulch Wind Park and Cassia Wind Farm alleges that an Idaho Power plan to require small-power producers to pay for nearly \$60 million in transmission upgrades to accommodate nearly 200 megawatts of new generation threatens the economic viability of a number of wind projects and will stifle further development of renewable energy in Idaho.

The developer of the Cassia wind projects, Jared Grover, is asking the Idaho Public Utilities Commission to determine that costs to upgrade the 138-kV transmission system in the Twin Falls area should be borne by all Idaho Power ratepayers, not just small-power producers.

Cassia Wind Farm is a 10.5-MW facility with five, 2.1 MW turbines. Cassia Gulch Wind Park is an 18.9-MW project that will include nine, 2.1-MW turbines. Both projects, in the Bell Rapids area near Hagerman, were slated to be online by Dec. 31. Grover is not disputing developers paying for new feeder lines and substations to interconnect with Idaho Power's grid, but says the developers should not have to finance upgrades to the "backbone" of Idaho Power's transmission system.

Wind developers maintain that FERC does not require that QF projects pay all interconnection costs. It is up to state commission to determine interconnection costs, the developers argue. The wind developers argue that Idaho Power's tariff for interconnection, Schedule 72, says QFs are responsible to pay for the interconnection between the generation facility and the point of interconnection with the existing transmission grid. The tariff does not address responsibility for upgrades beyond that point, the developers say, adding that requiring new generators to bear the cost of grid upgrades discriminates in favor of older, existing generators.

Idaho Power argues that requiring ratepayers to pay for interconnections costs would amount to a ratepayer subsidy, violating the basic PURPA principle of "ratepayer neutrality" that says the cost to ratepayers should be no greater for PURPA projects than if the power was generated by the utility itself or purchased from another source. A decision favorable to the wind developers would result in more favorable treatment than that given Idaho Power's own generating units as well as independent, merchant generation sources and could adversely affect the utility's ability to require other developers to fund system improvements, according to Idaho Power. The utility claims a decision for the wind developers could result in economically inefficient siting decisions made by QFs because transmission costs are ignored.

Idaho Power maintains the upgrade is needed to ensure system reliability when a loss of transmission in some segments of the grid during a peak use period could create thermal overload on the lines remaining in service. The wind generators argue that there are less costly means of preventing overloads than major transmission upgrades such as curtailing predetermined amounts of generation during an outage.

At the filing of this report, the case remained to be resolved.

## East Idaho wind project gets commission approval

Case No. PAC-E-05-09, Order No. 3000

The commission approved a 20-year, \$72.7 million sales agreement between PacifiCorp and developers of the Schwendiman Wind LLC wind project 11 miles northeast of Idaho Falls.

The agreement was amended from an earlier agreement rejected by the commission because it did not include performance provisions required in similar wind projects across the state to ensure that customers receive the electrical generation for which they are paying.

Under the amended agreement, Utah Power will buy the net output of 7.15 average megawatts from the project's eight 2.5 MW wind generators. The proposed agreement requires that output from the project fall within 10 percent of its forecasted monthly capacity. If output falls outside that 10 percent, Schwendiman will be paid only an energy rate with the capacity component reduced. The capacity component accounts for about one-third the total energy rate.

Commissioner Marsha Smith issued a separate concurring opinion, agreeing with the commission majority that the amended purchase power agreement is the result of negotiation and an amicable settlement. However, Commission Smith has consistently opposed the use of a performance band that applies a different payment method when generation fails to meet or exceeds output projections. "I believe the banding requirements operate as a penalty, not an incentive," Smith said. "I would have approved the Schwendiman Agreement originally submitted in this case."

The performance band provisions submitted by Schwendiman and PacifiCorp are different than provisions in other wind contracts with regulated utilities. Idaho Power submitted comments expressing concern that the Utah Power-Swendiman provisions could impact existing or future agreements between Idaho Power and wind developers. The commission said that is not the case. "Our decision in this case sets no precedent for our future regulation of such agreements and is intended to provide no basis for the amending of existing contracts," the commission said.

The agreement requires Schwendiman to reimburse Utah Power's costs for replacement power for up to 120 days if it fails to meet its operation date of July 31, 2007 and for up to 12 months if Utah Power is forced to terminate the agreement in the event of a seller default.

## Magic Wind attempts to get same agreement as Schwendiman

Case No. IPC-E-05-34, Order No. 30109

The commission denied a request from a Buhl wind developer to amend a sales agreement it had submitted to Idaho Power Co. to match the one approved on the Schwendiman project in eastern Idaho (see above item).

Magic Wind LLC, whose primary developer is Armand Eckert of Buhl, wanted to be paid for surplus energy based on an alternative pricing method than has been used for other Idaho Power wind contracts.

The commission ruled that because Idaho Power did not agree to the alternative pricing method, the utility could not be forced to alter the sales agreement.

The commission ruling was unanimous, but Commissioner Marsha Smith issued a separate concurring opinion.

Magic Wind plans to install eight 2.5-megawatt wind turbines eight miles northwest of Buhl. In August 2005, the commission reduced the size of projects that can qualify for the published rate from 10 average-megawatts to 100 kilowatts. But because the Magic Wind project was already well on its way toward development, the commission granted the developer's request that the project be exempt from the size limit.

Because wind output is not predictable, the commission in 2004 approved a "90/110 performance band." When output from wind projects falls under 90 percent of projected output or more than 110 percent, the utility buying the wind is allowed to pay the developer less than the published avoided-cost rate. In that 2004 case, utilities argued for a lesser rate because when output is less than 90 percent, utilities must then find power from other sources that can be more expensive. When output is more than 110 percent, utilities said they might have to sell the energy in the surplus market or reduce output at a more economic generation plant.

In this Magic Wind case, Commissioner Marsha Smith issued a separate concurring opinion stating her continued opposition to the use of a performance band. "This case, however, is a question of which contract terms may be required, not whether the performance band is appropriate," she said. "I find it persuasive that Magic Wind previously signed and submitted to Idaho Power a contract with the terms that Idaho Power is now offering."

All of the Idaho Power wind contracts to date have included provisions that when energy purchases fall outside the performance band, the developer is paid 85 percent of the market price available at the time. Magic Wind submitted to Idaho Power a wind agreement including that provision. Later it asked the commission for a declaratory order requiring Idaho Power to pay Magic Wind for surplus energy under a different formula than 85 percent of market price. Instead, Magic Wind sought to be paid for surplus energy under a formula similar to one adopted in a sales agreement between PacifiCorp and the Schwendiman wind project in eastern Idaho. The price for nonconforming energy in the Schwendiman case is based on a fixed rate, not variable market rates. The fixed rate includes the use of the commission's already published avoided-cost rate along with an approximate 14.5 percent discount that would be applied to nonconforming energy.

The commission approved the fixed-rate method in the Schwendiman case because it was reasonable and both parties agreed to the alternative formula. The Magic Wind and Idaho Power case is different, the commission said, because the parties are not in agreement. In its order approving the Schwendiman method, the commissions said, "Our decision in this case sets no precedent for future regulation of such agreements and is intended to provide no basis for the amending of existing contracts."

Idaho Power said the Magic Wind proposal failed to acknowledge the role market prices play in determining the cost Idaho Power is likely to incur should Magic Wind fail to meet projected output.

Elimination of market prices from consideration shifts costs and risks that should be borne by Magic Wind to customers of Idaho Power, the utility argued.

Magic Wind, other wind developers, the Renewable Northwest Project and the Northwest Energy Coalition, argued that the contract terms demanded by Idaho Power are inconsistent with PURPA regulations because they result in wind developers receiving less than the published rate. The unpredictability of market prices makes it difficult for financial institutions to invest in wind, they argued.

Idaho Power said the performance band is not a computation of avoided cost, but a measurement of damages. If a wind project performs as agreed, it receives the published rate. Idaho Power said its method of pricing contracts has not discouraged investment in wind. The utility has signed 14 wind contracts totaling 187 megawatts since the performance band was put in place.

**(At this report's publication deadline, the commission had yet to rule on Idaho Power's application for a sales agreement with Magic Wind under the original pricing method. The sales agreement has since been filed as a new case, IPC-E-06-26.)**

Commission approves sales agreements with four wind projects  
IPC-E-05-30, 31, 32, 33

In early 2006, the commission approved Idaho Power Co. sales agreements with the developer of four wind parks scheduled to be built in south-central and eastern Idaho. The developer of all four projects is James Carkulis of the Montana-based Exergy Development Group. All four projects, if approved, were slated to start producing energy in November 2006 and be in full operation by May 2007.

The four projects, all of which will be paid for delivery of 10 average-megawatts a month to Idaho Power, include:

**Milner Dam Wind Park** (IPC-E-05-30) – Located about a mile west of Milner Dam (west of Burley) in Cassia County, this project includes 12, 1.5-megawatt turbines.

**Lava Beds Wind Park** (IPC-E-05-31) – Located between Blackfoot and Arco, this project is also 12, 1.5-MW turbines.

**Notch Butte Wind Park** (IPC-E-05-32) – Located between Twin Falls and Shoshone, this project is also 12, 1.5-MW turbines.

**Salmon Falls Wind Park** (IPC-E-05-33) – Located near Hagerman and south of Bell Rapids, this project includes 14, 1.5-MW turbines.

The commission agreed with Idaho Power's contention that the projects were sufficiently far enough along in development that they should be grandfathered from a commission order in August 2005 that temporarily reduced – from 10 average megawatts to 100 kilowatts – the size of projects that could qualify for a rate published by the commission for renewable projects under PURPA provisions.

# IRPs: Planning for the future

*The commission requires regulated utilities to file an Integrated Resource Plan (IRP) every two years. The 10-year growth plan projects future load requirements and how utilities plan to deliver low-cost, reliable energy to its customers. The document is only a guide and not a commitment to resource acquisition.*

## Case No. IPC-E-06-24

At the filing of this report, Idaho Power Co. was seeking regulatory acceptance of its IRP, which calls for 1,300 MW of resource additions to meet the demands of its growing customer base.

The plan includes a 250-megawatt coal addition in 2013. Idaho Power said it does not know specifically where this addition will be located, but states that one of its best near-term alternatives for expansion at an existing coal plant is the addition of a fifth unit at the Jim Bridger Plant. Idaho Power owns a one-third share of the coal-fired Bridger plant near Rock Springs, Wyoming.

The IRP calls for 1,300 MW of resource additions as well as conservation programs designed to reduce peak demand by 187 MW and average load by 88 MW. Transmission upgrades, particularly to the McNary-Boise transmission line, will bring in more power from the Pacific Northwest, adding another 285 MW of capacity. McNary Dam, the source for the McNary-Boise transmission line, is located near Umatilla, in north-central Oregon.

Idaho Power anticipates its customer base will increase from about 455,000 customers today to about 680,000 by the end of 2025, an increase of 11,000 to 12,000 customers each year.

The company's immediate goals for the rest of 2006 were to conclude a 100-MW wind RFP, notify short-listed bidders in a solicitation of 100 MW of geothermal electricity and initiate the McNary-Boise transmission upgrade. In 2007, the company plans to bring 100 MW of wind on line. In 2008, the company plans to acquire another 170 MW by expanding the Danskin natural gas plant near Mountain

## **Idaho Power seeking approval of gas peaker**

### Case No. IPC-E-06-09

Idaho Power's 2004 IRP included an additional gas peaker plant at the existing 40-acre Evander Andrews Power Complex near Mountain Home. The complex is already the home of two 45-MW gas fired generators built by Idaho Power in 2001. The company was waiting commission approval of the plant at the filing of this report.

Idaho Power's application includes a commitment cost of \$60 million the company would like included in base rates if the commission finds the costs were prudently incurred. Idaho Power proposes that capital costs exceeding \$60 million be absorbed by the company and not passed on to customers. The commitment estimate does not include an upper-limit estimate of \$22.8 million to construct transmission and substation facilities needed to interconnect the project to Idaho Power's transmission system. Idaho Power's 230 kV transmission system is about seven miles from the Evander Andrews site.

After a bid process that included 31 proposals from nine companies, Idaho Power selected Siemens Power Generation, Inc. to build the plant, the same firm that constructed the company's Bennett Mountain Power Plant, also near Mountain Home. Once the plant is built, ownership would be transferred to Idaho Power. If approved, the plant is anticipated to be available to meet peak demand in the summer of 2008.

Home and evaluate and initiate more conservation programs. In about 2017, the company hopes to acquire another 250 MW from a regional facility using an advanced clean-coal technology called Integrated Gasification Combined Cycle. IGCC developers have expressed interest in Pocatello and Soda Springs as possible sites for the advanced coal technology. In 2023, Idaho Power may be able to acquire 250 MW from an anticipated nuclear facility at the Idaho National Laboratory in eastern Idaho.

**Case No. AVU-E-05-08**  
**Order No. 29943**

In January, the commission accepted Avista Utilities' 10-year plan to meet load growth. The plan relies on 400 megawatts of wind, 250 MW of coal and 180 MW from other renewable resources by 2016 to meet growing electrical demand.

The commission staff, which operates separately from the commission, commended Avista on its commitment to renewable sources, but noted it may be too early to determine where Avista will be able to get its power. "It is important to recognize that new resource additions are not needed for several years. Consequently, the quantity and mix of Avista's resource selections will likely change in future IRPs as conditions change, fuel prices become more certain and technology advances," said commission staff in written comments.

Staff also encouraged the company to continue to include transmission planning into its long-range planning process. Cooperation with regional power entities and transmission planning will allow the utility access to more low-cost power across the Northwest, commission staff said.

The Renewable Northwest Project and the Northwest Energy Coalition also filed comments, commending Avista's plan to rely more on renewable, rather than thermal, resources. The organizations asked that Avista delay any commitments to coal plants until further research into clean-coal technology and emissions sequestration is completed.

Avista projects it will grow to 350,000 customers in its three-state territory by 2007 – up from the current approximate 330,000 – and to 485,000 customers in 2026. There are about 110,000 customers in northern Idaho.

Without adding to its generation, the company would begin to experience energy deficits in 2010.

To meet growth, the company's preferred resource portfolio by 2016 is a mix of generation sources, including 400 megawatts of wind, 250 MW from coal and another 80 MW from small renewable projects. The company is not proposing any additional natural gas-fired generation due to the high level of natural gas generation already in the company's portfolio, the rising price of natural gas and the volatility that creates.

Resource requirements are 69 MW lower because of planned conservation programs and 52 MW lower because of efficiency upgrades to existing generating plants.

By 2026, the company plans to have added a total of 1,332 MW of new capacity. Of that 650 MW would come from wind, 450 MW from coal, 180 MW from other renewables and 52 MW from efficiency upgrades. Needs would be 138 MW lower due to conservation programs.

The company currently has about 1,663 MW of installed capacity, 979 MW of that coming from hydroelectric projects and 683 MW from thermal sources, primarily natural gas.

Avista is also in the process of implementing a transmission upgrade plan to add more than 100 circuit miles of new 230 kV transmission line and will later increase its capacity another 50 miles. The company is also building two new 230-kV substations and upgrading three existing transmission substations.

**PacifiCorp's IRP**, accepted in 2005, plans to meet projected electrical demands by adding three natural gas power plants and two coal plants in its six-state territory and increasing its capacity through conservation programs. In addition to the new coal and natural gas plants, PacifiCorp is continuing to pursue a commitment to procure 1,400 megawatts in renewable resources, such as wind.

PacifiCorp projects an annual growth in electrical demand of 3.8 percent in its three eastern states (Utah, Wyoming and Idaho) and 1.5 percent in its western states (Oregon, Washington and California). Without developing further resources, the utility would face a shortfall by 2009 and be 2800 MW short by 2015.

The company proposed to add 2,629 MW from two coal and two natural gas plants in its eastern territory and one natural gas plant in its western territory. None are proposed in Idaho. PacifiCorp also proposes to add 1,200 MW in purchased power from other suppliers and 100 MW in contracts from small-power producers through federal PURPA requirements. It also proposes the addition of 177 MW from load-control programs involving residential and commercial air conditioners, irrigation and commercial and industrial lighting. PacifiCorp hopes to produce 250 average megawatts in energy and capacity savings achieved through technological improvements in appliances, equipment and buildings.

Two major issues impacting PacifiCorp's resource choices are the future cost of natural gas and the future cost of or constraints on air emissions – carbon dioxide emissions in particular – that may be imposed on the company by government regulation.

# Conservation, energy efficiency

## **De-coupling: Case seeks to remove financial disincentives to conservation** **Case No. IPC-E-04-15**

State regulators, Idaho Power Company and representatives of environmental and industrial groups engaged in discussions during 2006 over the establishment of a rate mechanism that will remove financial barriers to utilities that want to invest in and encourage energy efficiency and conservation programs.

Idaho Power, like other electric utilities, recovers most of its fixed costs of doing business through the rates it charges customers. The Idaho Public Utilities Commission sets rates based on assumptions that project a utility's annual sales. If energy efficiency programs are successful, electrical demand is decreased and sales decline. If sales lag below rate case assumptions, the utility may not recover its commission-approved fixed-cost revenue requirement, which can be harmful to a utility's financial performance

Following Idaho Power's 2003 rate case, the commission opened a new case to investigate financial disincentives to utility investment in energy efficiency programs. Commission staff, representatives from the company, the Northwest Energy Coalition and Industrial Customers of Idaho Power participated in workshops to address the issue.

Idaho Power has filed an application and testimony favoring an annual "Fixed-Cost Adjustment," that "decouples" or separates utility sales from revenue so there is less of a disincentive for companies to invest in energy efficiencies. The Fixed-Cost Adjustment, if implemented, would annually adjust rates up or down to recover the difference between the fixed costs authorized by the commission in the most recent rate case and the fixed costs the utility actually recovered from customers during the previous year.

With the use of this proposed rate mechanism, the utility is less impacted by decreases in energy sales, thus removing any disincentives for utilities to aggressively pursue opportunities to reduce electric consumption.

A study of Idaho Power's fixed costs collected and fixed costs allowed by the commission over the last 10 years shows that residential and small-commercial customers would have received increases during some of those 10 years and decreases in other years. The study showed that the average monthly impact to a residential bill over the entire 10-year period was a 64-cent increase. To the average commercial customer, the monthly impact was a 31-cent increase.

Idaho Power is proposing that the initial Fixed-Cost Adjustment apply only to residential and small-commercial customers and that a cap allowing no more than a 3 percent increase be allowed even if there were years when the difference between actual sales and fixed costs allowed was greater than 3 percent.

Customers benefit from energy efficiency programs because they preclude or delay the need for building new power plants, preclude or delay expansion of distribution and transmission facilities, reduce electrical demand during peak periods when power is most expensive, reduce pollution and provide other environmental benefits.

If approved, the FCA adjustment would likely be made at the same time as the yearly power cost adjustment, or PCA. The PCA annually adjusts rates up or down to account for above-normal or below-normal power supply costs.

## Commission OKs efficiency rider for PacifiCorp customers

Case No. PAC-E-05-10, Order No. 29976

In March, the commission approved a 1.5 percent rider to the bills of PacifiCorp's 62,000 customers in southeastern Idaho to fund energy conservation programs. The commission believes the DSM (demand-side management) rider is cost-effective for customers because the efficiency programs preclude or delay the utility's need to build additional power plants or buy power from other sources to meet growing customer demand.

The rider will add about \$1 to the monthly bill of an average residential customer who uses 790 kilowatt-hours a month. The commission approved the rider, which became effective May 1, on a 2-1 vote with Commissioner Dennis Hansen dissenting from Commissioners Paul Kjellander and Marsha Smith. Hansen said he supports well-planned DSM programs, but believes one of PacifiCorp's programs to pay customers to dispose of inefficient refrigerators and freezers is not cost-effective.

The commission delayed approval of an earlier proposal by PacifiCorp because the array of programs offered provided more benefit for other customer classes than they did for the residential class. The company later submitted a revised proposal that provides a Home Energy Efficiency Incentive program for residential customers.

Some of the programs offered will include:

- An irrigation efficiency program to complement an existing irrigation load control program. The program offers irrigators no-cost equipment exchange, equipment testing and financial incentives for energy efficiency measures.
- Energy efficiency measures for commercial and industrial customers that include efficient lighting, premium motors and mechanical upgrades associated with heating and cooling.
- Incentives to promote home energy efficiencies involving appliances, water heaters, lighting, heating and cooling equipment, windows and insulation. More specific details of this program are to be submitted to the commission by no later than April 30.
- A refrigerator-recycling program for residential customers called "See Ya Later Refrigerator." The program offers incentives to homeowners and landlords to discontinue use of second refrigerators and freezers or replace them with more energy efficient models.
- An increase in Utah Power's low-income weatherization program to \$150,000 from \$100,000 and an increase in the maximum rebate allowed per weatherized home from \$1,000 to \$1,500.

The commission said cost-effective DSM programs provide benefits even to non-participants because the programs reduce the company's overall cost of serving its customers. It also benefits all Idaho customers by reducing Idaho's allocation of PacifiCorp's power supply costs in its six-state territory.

Rocky Mountain Power will be required to file a report with the commission demonstrating the programs' cost-effectiveness. All expenses related to the programs will be kept in a deferred account and rebated to customers or invested in new programs if the programs proposed by the company are not found to be cost-effective.

## Idaho Power allowed to continue with net metering programs

Case No. IPC-E-05-00, Order No. 30037

In May, the commission granted Idaho Power Company's request to extend for another year two energy conservation programs offered in the Emmett area.

The pilot programs, Time-of-Use and Energy Watch, are available to customers who volunteer to participate and have advanced meter readers installed.

Advanced meter readers (AMR) can be read from a remote location without having to enter a customer's property and can provide the company and customer with hourly meter readings. Some AMR systems have the ability to inform customers of current electric prices, potentially allowing them to manage their electrical use and reduce their bills.

The commission agreed with the company that the extra year is needed to collect more data and provide further evaluation before the programs can be expanded to serve a larger section of Idaho Power's territory. "We believe the time-of-use pricing pilots to be important programs with potential benefit to both customers and the company," the commission said.

Under the Energy Watch Pilot Program, Idaho Power allows volunteers to pay the less expensive non-summer rate (5.08 cents per kWh) instead of the summer rate (5.72 cents per kWh) except during the company's selected Energy Watch periods, when the rate is 20 cents per kWh. The company notifies volunteer customers either by telephone or by e-mail by 4 p.m. a day before the Energy Watch period. Energy Watch periods can occur on any weekday from June 15 through August 15 for four hours between 5 and 9 p.m. Energy Watch periods will occur on no more than 10 days from June 15 to August 15 for a total of 40 hours.

The Time-of-Day Pilot Program allows volunteers to shift their use to off-peak periods when the rate is lower. In order to increase the financial incentive for customers to participate, Idaho Power is increasing the difference between off-peak and on-peak rates.

In another minor change from last year's programs, Idaho Power proposed to limit those who can participate to customers who use 300 kilowatt-hours per month or more. The commission said limiting the

programs' availability to customers with the capability to shift loads significant enough to gain valuable statistical information is reasonable.

Idaho Power reports that customers in the Time-of-Day program saved about 5 percent on their bills during last summer and customers on Energy Watch saved about 10 percent. The Energy Watch participants were able to cause a statistically significant reduction in Idaho Power's overall load requirements during peak hours when power is most expensive.

# SERVICE AREAS OF INVESTOR OWNED ELECTRIC UTILITIES IN IDAHO

