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

2001 Average Number of Customers/Avg. Revenue/kwh
(Computed from data available in FERC Form 1 Annual Reports)
318,076 Residential Customers/$0.0609
62,178 Commercial Customers/$0.0491
107 Industrial Customers/$0.0400

Avista Utilities

2001 Average Number of Customers/Avg. Revenue/kwh
(Computed from data available in FERC Form 1 Annual Reports)
89,837 Residential Customers/$0.0564
14,576 Commercial Customers/$0.0587
538 Industrial Customers/$0.0477

2001 Average Number of Customers/Avg. Revenue/kwh
(Computed from data available in FERC Form 1 Annual Reports)

PacifiCorp/Utah Power

44,644 Residential Customers/$0.0636
6,379 Commercial Customer/$0.0648
5,411 Industrial Customer/$0.0353

Idaho's Electricity Rates Are Among The Lowest In The Nation

Power Rates in Idaho

As of Oct. 1, 2002

These rates do not include customer charges. Not all available rate schedules are shown for each utility.

IDAHO POWER COMPANY

Residential -- $0.0672
(Rate is $0.06867, but with BPA credit of $.001506, reduced rate is $0.0672.)

Commercial
Small commercial — $0.0769, plus $2.51 per kW demand charge
Large commercial — $0.04552, plus $2.73 per kW demand charge

Industrial
Large industry — $0.0428; plus $2.73 per kW demand charge
Irrigation — $0.0418 in season (not including BPA credit); plus $3.58 per kW demand charge in season.

AVISTA UTILITIES

Residential
First 600 kWh — $0.0517
All use over 600 kWh — $0.0607

Commercial
Small commercial — $0.0797 plus $3.50 per kW demand charge for demand more than 20 kW
Large commercial — $0.05022 plus $225 for first 50kW of demand or less and $2.75 per kW for demand over 50 kW

Industrial
Large industry — $0.0345 per kWh plus $7,500 for first 3,000 kVA (kilovolt-amps) of demand or less and $2.25 per kVA for demand over 3,000 kVA.

PACIFICORP-UTAH POWER

Residential
From May to October — $0.0734
From November to April — $0.0501
Time of Day residential rates
On-peak use from May to October — $0.0801
Off-peak use from May to October — $0.0113
On-peak use from November to April — $0.0648
Off-peak use from November to April — $0.0082

Commercial
Small commercial, May to October — $0.0847
Small commercial, November to April — $0.752
Large commercial — $0.0288 plus $10.68 per kW demand charge from May to October and a $8.79 kW demand charge from November to April.

Industrial
Small industry — $0.0326 per kWh plus $8.79 per kW demand charge from May to October and a $6.59 per kW demand charge from November to April.
Irrigation (In-season)
First 25,000 kWh — $0.0264, plus $4.05 per kW demand
Next 225,000 kWh — $0.0101, plus $4.05 per kW demand
All additional kWh -- $-0.0029, plus $4.05 per kW demand

Electric Utility Case Reviews

Idaho Power Company

Idaho Power Company
1220 W. Idaho Street
P O Box 70
Boise, ID 83707

800-488-6161
208-388-2323
(Treasure Valley)

Number of Customers = 380,361

Idaho Power Co. is Idaho's largest electric utility. The utility typically generates 55 percent of its electricity at hydroelectric dams on the Snake River. Due to a second year of poor hydro conditions in 2001, only 43 percent of the utility's electric generation came from hydro with increased reliance on the company's coal- and gas-fired plants (at Jim Bridger, Wyoming; Boardman, Oregon; Valmy, Nevada, and Mountain Home, Idaho) and power purchases on the wholesale market. Less than 5 percent of Idaho Power's generation comes from co-generators and small independent power producers.

In 2001, the average Idaho Power household used 13,944 kWh, up 4.4 percent from the 13,535 kWh in 2000. This figure averages residential customers with electric space and water heating with those who do not use electricity for these uses.

Nov. 21, 2001

PUC ORDERS CONSERVATION, DELAYS SURCHARGE

Case No. IPC-E-01-13, Order No. 28894

The commission directed Idaho Power Co. to implement **conservation programs** in time for this winter's heating season and to use existing resources to cover the costs of the short-term programs. The company requested a two-year surcharge to fund the programs.

The programs, called demand side management programs, include financial incentives to residential customers such as compact fluorescent bulb coupons, Energy Star appliance incentives, high efficiency air conditioner and heat pump rebates, weatherization loans and low-income assistance.

Idaho Power asked that a **two-year tariff rider** be added to customer bills to generate $2.6 million to fund the programs. The rider would have resulted in an increase to the average residential bill of about 28 cents a month. The commission decided not to grant the rider at this time. "Given the large rate increases authorized already this year, the commission is reluctant to raise rates any further by implementing a tariff rider at this time, even to fund a worthy endeavor such as this," the commissioners said.

Commissioners noted that due to extremely low water conditions and unusually high wholesale power costs, Idaho Power's residential rates have increased a combined average of 31 percent in the last seven months. Had demand-side management programs such as those proposed now been in place during the last year, they "may have reduced power supply costs and the subsequent increases in Idaho Power's rate," the commissioners said.

Feb. 13, 2002

NET METERING RATE OK'D, BUT IPC ASKED TO DO MORE

Case No. IPC-E-01-39, Order No. 28951

The Idaho Public Utilities Commission wants Idaho Power Co. to expand a renewable energy program to include people in all customer classes, such as irrigation customers, dairy farmers using biomass technology, and generators of wind power. Idaho Power proposed to offer its **net metering** program only to residential and small commercial customers.

Net metering allows customers who generate their own power through means such as solar panels, windmills, fuel cells or small generators, to measure how much power they are consuming and how much excess power they are selling back to the power company. The meter is bi-directional. All energy supplied by the company to the customer will cause the meter to run forward while all energy delivered by the customer to the company will cause the meter to run backward. Customers get credits when they are generating more power than they are consuming.

The commission approved Idaho Power's proposed tariff schedule for residential and small commercial customers who want to participate in net metering. But comments filed by organizations, including the Idaho Farm Bureau, Idaho Rural Council, Renewable Energy Advocates and the Idaho Department of Water Resources, supported expanding the program to include all customer classes and to accept bigger projects than those limited to 25 kW capacity as proposed by Idaho Power.

The commission approved the net metering rate proposed by Idaho Power for just residential and commercial customers and agreed to the company's 25 kW limit for those two classes, but ordered the utility to file an expanded net metering program within six weeks that includes the remaining customer classes and higher capacity allowances for those other classes.

The commission also approved Idaho Power's proposed **2.9 MW capacity limit** for the combined generation of all net metering projects, but agreed with those who said that if the limit is reached, the commission will review it for a possible increase.

Idaho Power opposed extending the program to irrigation and industrial customers because those customers can already negotiate contracts to generate renewable energy to sell to the utility under the Public Utilities Regulatory Policies Act (PURPA). But the commission said the primary purpose of net metering is not as much to generate power as it is to provide customers the opportunity to offset their own energy requirements and turn back their meter, which can be particularly helpful during this time of high electric bills.

Idaho Power also opposed increasing the 25 kW limit on each customer-owned generation facility because of potential safety and service issues and concerns about stress on the regional electric grid. However, the commission said Idaho Power's 25 kW limit is "unreasonably low" for customer classes other than residential and small commercial. "We find a more reasonable limit for irrigators, dairies and other customer classes is in the range between 100 to 125 kW," the commission said. The commission asked the company to detail its concerns in the upcoming filing and offer proposed solutions.

April 3, 2002

UTILITY DIRECTED TO FORM ENERGY EFFICIENCY GROUP

Case No. IPC-E-01-13, Order No. 28993

The commission ordered Idaho Power Co. to immediately form an Energy Efficiency Advisory Group that will outline proposed long-term conservation programs. A commission order on Nov. 21, 2001, directed Idaho Power to form the advisory group. On March 14, the Land and Water Fund of the Rockies filed a motion asking the commission to enforce that order.

The commission did so, directing the company to appoint the members of the advisory group and establish a plan for implementing conservation programs by no later than May 2. "The deadline will prove to be a substantial task, but it is a situation of Idaho Power's own making," the commissioners said.

The company said it interpreted the original November order to mean it could appoint the advisory group after the commission had decided how the conservation programs would be funded. Idaho Power last year asked that a two-year tariff rider be added to customer bills to fund the programs. The rider would have resulted in an increase to the average residential bill of about 28 cents a month. The commissioners denied funding at that time, but said it would take the matter up this spring through the company's annual power cost adjustment process.

Commissioners said the language of the November order explicitly stated that Idaho Power would form the advisory group and create an implementation plan so that the necessary groundwork would be in place once the funding issue was resolved. "We do not understand how Idaho Power could construe this language in a manner that would justify waiting until the program was funded before convening the advisory group," the commissioners said. "Although it would be helpful for the advisory group to know the amount of funding that will be available, there is no reason it cannot investigate and prioritize desirable conservation programs without this information."

"In short, the commission is disappointed that Idaho Power has done so little to comply" with the November order, commissioners said. "Although we do not currently hold the company in contempt, the commission does find Idaho Power's inaction to be a serious breach of compliance."

May 13, 2002

IDAHO POWER GRANTED $256 MILLION DEFERRAL, BUT BOND PLAN DENIED

Case No. IPC-E-02-2, IPC-E-02-3. Order No. 29026

Declaring it refuses to mortgage Idaho Power ratepayers' future, the Idaho Public Utilities Commission denied the utility's request to spread the past year's power supply costs over three years by **issuing bonds.**

Instead, the commission authorized recovery of nearly all the $255.9 million in cost recovery allowed in a one-year period. That will mean a slight increase for most residential customers, varying from 3 to 10 percent. However, residential customers who use more than 3,000 kWhs per month will notice a decrease because of the commission's decision to discontinue the residential tiered-rate structure.

"We find it unreasonable and contrary to the public interest to mortgage the future of ratepayers simply to achieve a small rate decrease this year," the commissioners said.

Uncertainties regarding water supply and market volatility led the commission to choose a one-year recovery plan for all but about $11.5 million of the $255.9 million in power supply costs. Commissioners rejected the three-year plan because of fears that another drought year or another period of high wholesale prices could result in customers paying for new increases while still paying for the 2001-02 power supply expenses.

"The commission does not make this decision lightly. We understand the hardships that last year's large rate increase is imposing on customers," the commissioners said. "However … the commission is very concerned about the unknown water and market conditions that lie ahead. We are also very reluctant to create a situation where customers are required to continue paying costs from this year on top of whatever increases may be required in future years."

A one-year recovery will take care of nearly all the deferred costs remaining from a sustained period of extraordinarily high wholesale prices at the same time that hydro-dependent Idaho Power customers were experiencing the second worst drought in 75 years. Ratepayers also avoid paying bond issuance and finance costs of about $21 million with the commission's decision to deny Idaho Power's three-year bond plan.

"We certainly hope that this is the last year Idaho Power ratepayers will be faced with such extraordinarily high" power supply costs, the commissioners said. "However, as we have learned over the past two years, there are no guarantees about future stream flows or market prices," commissioners said.

The commission also authorized Idaho Power to implement **a tariff to raise about $2.6 million for conservation programs** that can mitigate the impact of this rate increase as well as those that may occur in the future. For example, a coupon program for compact fluorescent bulbs could offset the increase and, in some cases, result in lower bills. The tariff will be a 30-cent per month charge to residential customers.

The commission denied about $17.4 million of Idaho Power's cost recovery request. Most of that – $15.1 million – is money the utility sought to recover as revenue the company would have earned had it sold power to irrigation customers who participated in the company's load reduction program. Another $1.2 million the company spent installing mobile diesel generators was denied as was $1.1 million in costs associated with construction of the utility's natural gas plant in Mountain Home. The commission also discounted, by $4.3 million, trading transactions from July 2001 through March of this year.

With the end of the **tiered-rate structure**, residential customers will pay a flat rate of 7.1 cents per kWh. The result will be larger increases for residential customers who benefited from the tiered-rate now in place. The monthly bill of a residential customer who uses 500 kWhs per month will increase from about $33.34 per month to $36.85, about a 10.5 percent increase. The bill of a residential customer who uses 1,500 kWhs per month will increase from $100.62 per month to about $105.52, or a 4.7 percent increase. A customer who uses 3,000 kWhs per month will see a decrease from $219.36 to about $208.23, about a 5 percent decrease.

Tiered rates created unanticipated problems when Idaho Power's meter reading cycle extended beyond 30 days. A 32- or 33-day billing period sometimes pushed customers into a higher rate block, forcing them to pay more than they would have under a normal 30-day cycle. The commission was also concerned about the public's perception of tiered rates. Many customers blamed their high energy bills on the tiered rate rather than the primary cause: an average 31 percent residential increase over the previous winter's rate. Bills of customers using about 2,000 kWhs per month were about the same with the tiered rate as they would have been with a flat surcharge. The tiered rate was designed to send a strong conservation signal and allocate a portion of less expensive electricity to all customers to ensure a minimal amount of energy essential for customer health and safety.

"From the public comments we received, it was apparent many ratepayers did not understand the purpose or actual dollar effect of tiered rates," commissioners said. Of the 274 written comments the commission received about this case, 132 specifically mentioned opposition to the tiered rates while only nine supported their continued use. More than 100 of those commenting mentioned they lived in all-electric homes where it is difficult to drastically reduce consumption and fall into a lower-rate tier.

While the commission directed Idaho Power to recover nearly all the $255.9 million in approved power supply costs in one year, it did allow the deferring of $11.5 million in costs allocated to customers in the irrigation (Schedule 24) and small general service (Schedule 7) classes into a second year. Customers in those classes will experience no increases as a result.

June 11, 2002

IPUC ACCEPTS IDAHO POWER, FMC-ASTARIS SETTLEMENT

Case No. IPC-E-01-43, Order No. 29050

At the urging of the Idaho Public Utilities Commission, Idaho Power Co., Astaris LLC and the staff of the commission have resolved potentially costly and time-consuming contract issues in a manner that benefits both companies and Idaho Power ratepayers.

"The result is a financial benefit to ratepayers and it resolves costly matters in the courts," said Commission President Paul Kjellander.

During last year's season of record drought and extremely high wholesale market prices for power, Idaho Power entered into a **voluntary load reduction program** with Astaris, a phosphorous plant near Pocatello. Astaris agreed to consume no more than 70 megawatts of the 120 MWs of power Idaho Power had agreed to provide and Astaris had agreed to take each year under a 1997 agreement.

In the 2001 load reduction agreement, Idaho Power agreed to pay Astaris 15.9 cents for each kWh not used. That prevented Idaho Power from having to go to the market and buy the remaining 50 MW at wholesale prices that were nearly twice as high as the agreed upon 15.9 cents.

The load reduction program began in April 2001, but in December, Astaris decided to close its Pocatello plant, which then reverted to FMC. That closure, coupled with wholesale prices returning to normal levels, prompted the commission, in January of this year, to initiate an investigation into the continued reasonableness of the load reduction program.

In the wake of its plant closure, Astaris, earlier this year initiated court action against Idaho Power in the Fourth Judicial District seeking relief from its **1997 "take or pay" agreement** with Idaho Power.

After an evidentiary hearing in late February, the commission directed the parties to attend a settlement conference, which was followed by protracted negotiations. The parties signed a settlement on June 6 and this order by the commission adopts that settlement.

Under the settlement, FMC/Astaris has agreed to a reduction by $5 million in the payments it would have otherwise received under the voluntary load reduction agreement, which translates into savings for ratepayers. Idaho Power also agreed to distribute $425,000 of its share of the load reduction program's savings to Idaho Power ratepayers through its yearly power cost adjustment mechanism.

FMC/Astaris' take-or-pay obligation to Idaho Power will be reduced by $7.9 million. Idaho Power has agreed it will not seek $6.9 million of that in recovery from ratepayers and include only $1 million for possible recovery through the power cost adjustment mechanism. FMC/Astaris also agreed that it would dismiss its state district court action against Idaho Power.

June 28, 2002

DEFERRAL GRANTED FOR INDUSTRIAL CUSTOMERS

Case No. IPC-E-02-2, Order No. 29065

Industrial customers of Idaho Power will be able to spread their portion of the costs they owe to Idaho Power over a two-year period, according to an order issued by the commission.

The Industrial Customers of Idaho Power petitioned the commission for reconsideration of an order it issued on May 13 authorizing Idaho Power to recover, over one year, $244.4 million of power supply expenses the utility incurred during 2001-02. About $91.7 million of that is assessed to the industrial class. The result to most industrial customers of Idaho Power would have been about a 4.7 percent increase.

Industrial Customers of Idaho Power requested that the commission authorize the industrial customers to spread costs over a five-year period. The commission said it would not be prudent to spread costs over five years, but it did allow industrial customers to spread their costs over two years – $87.5 million in the current power cost adjustment (PCA) year and $4.2 million over the 2003-2004 PCA year. While that spreads the costs of one year's power supply expenses over two years for industrial customers, it does eliminate the 4.7 percent increase industrial customers would have paid this year.

On another matter, but included in the order, the commission said it will allow Idaho Power to collect a **carrying charge** on money the utility invests in the early stages of implementing commission-mandated conservation, or demand side management (DSM), programs.

In its May 13 order, the commission approved a tariff rider on all Idaho Power customers to fund DSM programs. In this order, the commission said Idaho Power is entitled to recover interest to the extent DSM programs are pre-funded by the utility in advance of funds being generated by the tariff rider. The company requested a 6 percent carrying charge. The commission granted 4 percent, based on the interest rate currently paid on customer deposits.

August 27, 2002

INTERCONNECTION TARIFF OK'D FOR SMALL GENERATORS

Case No. IPC-E-01-38, Order No. 29092

Idaho Power customers who generate their own power should have an easier time interconnecting with Idaho Power's electricity grid as a result of an updated process approved by the Idaho Public Utilities Commission.

Idaho Power proposed the updated procedure, which requires customers who generate their own power through means such as small wind or solar systems to pay for the costs of interconnection and agree to periodic inspections to ensure the safety and reliability of the generators.

The purpose of the changes is to provide a standard tariff for small, independent generators (called non-utility generators), which would enable a safe, economic and reliable interconnection with Idaho Power's electric grid.

The tariff is also to ensure that Idaho Power's other customers do not subsidize the costs associated with non-utility generation.

Idaho Power had originally requested that small generators pay for an annual independent inspection of the generation facilities, but the Idaho Rural Council and the Renewable Energy Advocates objected, maintaining that after an initial inspection, repeated inspections should not be required unless major modifications are made to the projects.

The commission ruled that small-generation projects – 25 kilowatts or fewer – be inspected only once every three years if the projects use interconnection equipment that meets nationally recognized standards and are approved by Idaho Power in advance. Renewed certification will be required if material modifications or additions are made. Projects larger than 25 kW would require annual inspection.

The commission also ruled that interconnection costs should be borne by the generator, not by the company and its ratepayers.

The commission cautioned Idaho Power Co. against making interconnection too difficult. "We put the company on notice that should it abuse its discretion in interconnect matters and thwart the development of non-utility generation, the commission will entertain a complaint and revisit this issue."

August 29, 2002

COMMISSION CLOSES GARNET CASE

Case No. IPC-E-01-42, Order No. 29085

The Idaho Public Utilities Commission closed its case on Idaho Power's petition to enter into a contract to buy power from the proposed Garnet power plant project near Middleton. Commissioners made clear that its decision does not mean the commission either endorses or opposes the Garnet project.

"This decision is no reflection on how the commission views the project," said Commissioner Marsha Smith. "This is merely a procedural decision."

Idaho Power filed a motion with the commission to vacate hearings about whether Idaho Power should be allowed to enter into contracts to buy power from the Garnet project because IDACORP, Garnet's corporate parent, and Garnet Energy LLC have been unable to obtain the financing necessary to construct the proposed 250-megwatt natural gas plant. Idaho Power asked that the matter be continued for at least 120 days to allow IDACORP and Garnet to find a creditworthy partner or make other financing arrangements.

A competing motion filed by Citizens for Responsible Land Use and Idaho Rural Council asked that the case be dismissed without prejudice. Commissioners said if IDACORP and Garnet are successful in finding financing for the project, it might open a new case with the commission.

The commission also ordered the company to file a report within 90 days on the progress of possible financing for Garnet. If financing has not been secured, the company must include in the report alternatives for meeting the expected 350-megawatt energy shortfall the company anticipates will occur by mid-2005.

August 30, 2002

IDAHO POWER'S 'LOST REVENUE' REQUEST DENIED

Case No. IPC-E-01-34, Order No. 29103

The Idaho Public Utilities Commission upheld its earlier denial of Idaho Power's request to collect an additional $12 million from its customers to recover potential lost revenue as the result of a load reduction program with irrigation customers last summer. Idaho Power is appealing the commission's decision to the state Supreme Court.

Earlier this year, the commission allowed Idaho Power to recover from customers the direct costs of the program, nearly $74 million. But, in an order issued April 15, the commission rejected the company's request to collect another $12 million in "lost revenue" – the amount, including interest, the company believes it might have received from the sale of power to irrigation customers had the program not been in operation. This order responds to Idaho Power's request for reconsideration.

The commission said the load reduction program was the prudent, if not the required, action to take in response to last year's crisis and that financial incentives to enact the program, such as recovery of lost revenue, were not needed.

"To charge ratepayers for lost revenue is unreasonable in the context of the crisis that existed," the commission said. "Requiring ratepayers to pay for energy they did not consume, but avoided, due to this program is also unreasonable."

When the commission adopted the program last year it told the company that the "direct costs and lost revenue impacts may (emphasis added) be treated as a purchase power expense" that the company could later recover from ratepayers.

"The commission finding did not guarantee that Idaho Power was entitled to recovery of alleged reduced/lost revenue that resulted from this program," the commission said in its April order. "Rather, the commission merely recognized that the issue of recovery would be considered."

October 21, 2002

MORE TIME ALLOWED ON IDAHO TIME-OF-USE STUDY

Case No. IPC-E-02-12, Order No. 29133

The Idaho Public Utilities Commission granted a motion by Idaho Power Co. and by commission staff to extend the comment deadline regarding an Idaho Power Co. report that says installing **time-of-use meters** for the utility's residential customers is too costly for the company and does not provide substantial benefit for customers. The comment deadline was moved to Dec. 6, 2002.

Time-of-use meters let customers know how many kilowatts they have consumed during peak and off-peak periods of the day. "Peak" periods are those times when demand on an electrical system is at its highest. By monitoring the amount of electricity consumed during certain hours of the day, customers can better measure the benefits by shifting their high use to off-peak hours. Some utilities offer customers a lower rate for shifting use to off-peak hours.

Earlier this year, the commission directed Idaho Power and its Energy Efficiency Advisory Group to consider implementing a pilot time-of-use metering program. The commission advised the company to "consider installing time-of-use meters in new subdivisions and the feasibility of allowing existing customers to voluntarily install time-of-use meters." The cost to customers of the meters and their installation would be spread over a number of years.

Idaho Power hired Christensen Associates to complete a study on the feasibility of implementing a time-of-use program. The study concluded that a mandatory time-of-use program would provide "very modest potential benefits" to customers. A voluntary program produces somewhat higher consumer benefits, the study said, but would result in net revenue losses to Idaho Power.

However, the study also said that a mandatory time-of-use program that operates only during critical peak periods could result in annual customer benefits of more than $1 million and has the potential of saving Idaho Power about $12 million in costs to operate its peaking facilities during those critical periods.

Costs to install the meters would be about $145 per customer or about $47 million for all of Idaho Power's residential customers. The incremental cost of the time-of-use meter compared to the standard meter would result in an increased charge to customers of about $1 a month, according to the Christensen study. The study further points out that an automated meter reading system that would allow customers to receive more timely information about their energy use would cost about $72 million.

October 22, 2002

DEPOSIT REQUIREMENTS FOR IRRIGATORS MODIFIED

Case No. IPC-E-02-9, Order No. 29132

The conditions that will require irrigators to pay a deposit to Idaho Power Co. and the way those deposits are calculated will change for the 2003 irrigation season. The Idaho Public Utilities Commission approved a request by Idaho Power to revise its deposit requirements for the utility's approximately 12,400 irrigation accounts.

The new rule requires a deposit from irrigation customers who get two or more reminder notices. The former rule required a deposit from customers with two or more late payments of $100 or more during a 12-month period. The new rule allows customers 45 days instead of 30 to pay their bills without incurring the requirement of a deposit in the following year.

The company is permitted to require deposits from customers with no credit history, from customers with a history of late payments, from customers for whom an order for relief has been entered under bankruptcy laws or for whom a receiver has been appointed in a court proceeding.

The second change approved is to compute the deposits based on the electrical characteristics of the customer's pump and motor rather than the old formula of basing the deposit on one-and-one-half times the customer's previous year highest monthly billing. According to Idaho Power, past bills are not always indicative of projected use for the next year because factors like crop rotation and weather may play a part in determining electrical use during the next growing season.

Idaho Power asserts that the proposed changes are revenue neutral for the company, although some customers will pay more under the new formula while others pay less.

Feb. 12, 2002

HULET CASE APPEALED TO STATE SUPREME COURT

Case No. IPC-E-01-25, Order Nos. 28860 and 28950

BOISE – Jay Hulet, an Owyhee County farmer, will appeal an Idaho Public Utilities Commission ruling that affirms Idaho Power Company's decision to bar Mr. Hulet from participating in the company's irrigation buy-back program. The Supreme Court is expected to hear oral arguments in early 2003.

Idaho Power did not allow Mr. Hulet to participate in the program because he did not submit a bid by the Feb. 28, 2001 deadline. Mr. Hulet claims he did not submit a bid because he was told by company representatives that irrigation customers with past due balances would not be allowed to bid. Company representatives claimed they informed Mr. Hulet that bids from irrigators with past arrearages would not be accepted, but that farmers could bid as long as they agreed to bring their accounts current. In fact, the company stated, 40 farmers with past due balances did submit bids. Of those, 36 were accepted into the program after their accounts became current. Mr. Hulet claims he was forced to transfer responsibility for his meters on his Murphy farms to his son so that his son could submit a bid. He also contends that because of false information he received from the company, he did not submit a bid on his Oreana farm and, as a result, has suffered serious financial harm.

After the commission dismissed Mr. Hulet's complaint, he petitioned for reconsideration. The commission granted reconsideration to Mr. Hulet and an evidentiary hearing was conducted on Jan. 15, 2002. Following that hearing, the commission again ruled that Mr. Hulet's complaint be dismissed. Mr. Hulet has appealed that ruling to the Supreme Court.

Avista Utilities

Avista generates most of its electricity at hydropower dams located in Washington, Idaho and Montana. The company also receives power from thermal plants in the same three states.

In 2001, the average Avista household used 11,106 kWh, almost a 5.2 percent decrease from the 11,719 kWh used during 2000. This figure averages residential customers with electric space and water heating with those who do not use electricity for these uses.

Jan. 31, 2002

WIND POWER RATE APPROVED FOR AVISTA CUSTOMERS

Case No. AVU-E-01-16, Order No. 28948

As of Feb. 1, customers of Avista Utilities were able to buy power generated by wind.

The Idaho Public Utilities Commission approved an optional wind power rate for Avista customers who volunteer to buy wind power. The wind power option is priced in blocks. Each $1 block of wind will equal 55kWh of energy.

Avista' customers have two options. They can purchase wind power in set monthly amounts like $2 or $3 each month. That amount would be set and not linked to monthly use. These customers, the company states, may view this payment as a contribution to support alternative energy production.

The second option is that customers can calculate and buy a selected percentage of wind-generated power to serve their average monthly load. For example, a customer who wants to volunteer half his 1,100 kWh average monthly load to be served by wind power would pay $10 per month (10 blocks at 55 kWh block multiplied by $1) and buy 550 kWhs of wind power. The wind power should be delivered to the company within one year of when the customer purchased the energy.

Avista will contract with PacifiCorp Power Marketing to buy the wind power. PPM is the sole purchaser of energy from the wind farm, which it then markets to customers throughout the West. The project, developed by FPL Energy, LLC, is said to be the largest single wind-powered renewable energy development in the world.

The optional wind power charge is in addition to all other charges contained in the customer's regular rate. The company maintains it will not earn money from the program. It will pay a premium of 1.8 cents per kWh for the wind power. The approximate $150,000 in revenue it anticipates to get from the program will be applied to program costs. The Idaho commission also made clear that all costs and benefits of the program be allocated

Avista Utilities

(physical address)
E 1411 Mission Ave.

(mailing address)
P O Box 3727
Spokane, WA 99220

800-727-9170

509-489-0500
(Spokane)
208-664-0421
(Coeur d'Alene)
208-743-5541
(Lewiston)
208-882-7511
(Moscow)

Number of Customers
= 104,951

only to those customers who volunteer to participate so that the program is not subsidized by other customers. All customer classes can participate.

The commission accepted a recommendation by intervenors in the case, including Idaho Rivers United and the Land and Water Fund of the Rockies, that Avista Utilities file a yearly report with the commission detailing program participation, the total number of kilowatt-hours generated and the amount spent on marketing. The intervenors also expressed hope that Avista will work toward acquiring renewable energy resources as part of the rate-base passed on to all customers. Voluntary programs, they contended, are good for a start, but are no substitute for integrating renewable energy into the base energy supply.

In Idaho, Avista serves about 90,000 residential customers and 60,000 commercial customers from about Grangeville north to Sandpoint.

October 3, 2002

COMMISSION APPROVES CONTINUATION OF SURCHARGE

Case No. AVU-E-02-6, Order No. 290130

The Idaho Public Utilities Commission approved continuation of a 19.4 percent surcharge that allows Avista Utilities to recover costs the company spent buying electricity on the wholesale market during the energy crisis of 2000-01.

The commission denied Avista's request to increase the interest on the remaining debt to 6 percent, opting to leave the current 4 percent in place.

Rates won't increase from current levels with the extension of the surcharge, which was implemented a year ago to recover $23.6 million of a total $78 million in power supply expenses accumulated during a two-year period when water supplies were low and prices on the wholesale electricity market reached record levels.

Avista's request continues the surcharge until Oct. 11, 2003, allowing the company to recover another $23.6 million of the current $48 million balance.

Very low stream flow conditions through the end of 2001 produced a shortfall in generation for the Spokane-based utility. That forced the utility into the expensive wholesale market to buy electricity to meet demand for its customers in Washington and northern Idaho.

At this time last year, the company asked for a **27-month surcharge** through 2003 to recover the debt incurred in 2000 and 2001. Instead, the commission approved a 12-month surcharge of 19.4 percent and directed the company to report back in a year on the status of the account at which time the commission would consider continuing the surcharge another 12 months.

Commission staff conducted a public workshop in Sandpoint to explain the company's proposal to legislators and customers.

"Even though I don't like the idea of surcharges going on, we know why they're there and we understand what happened in the marketplace," said Commission President Paul Kjellander. "We recognize the hardship this creates for customers, but I also think we need to recognize that by going this route we have granted what some people wanted by spreading these costs out over a number of years."

Commissioner Dennis Hansen said the power purchase decisions the company made at the time were prudent. "At the time Avista locked into the forward-looking prices, it looked like a very good decision," Hansen said. "But the circumstances changed greatly," Hansen said, referring to the rapid decline in wholesale prices. "It was a twist of fate and not of mismanagement," he said.

The commission disallowed about $1.5 million Avista wanted included in the power cost recovery. That included about $900,000 in capital costs from the company's generation plants at Kettle Falls, Devil's Gap and Othello. Those costs may be deferred for consideration in a future rate case. The remainder denied, pending additional investigation, was about $579,000 in fuel costs for the Coyote Springs plant.

Avista claimed recovery of the power supply expenses will improve the company's credit ratings, which are below investment grade. Improved ratings can help the company refinance long-term debt on more reasonable terms.

To mitigate the increased power costs, Avista said it increased operation of its thermal resources and aggressively pursued conservation and load curtailment programs. However, the company said the costs associated with the hydroelectric conditions, the cost of short-term power market purchases and increased thermal fuel costs exceeded the benefits these measures provided.

September 26, 2002

PURPA FORMULA ADOPTED FOR AVISTA, OTHER UTILITIES

Case No. GNR-E-02-2, Order No. 29124

The Idaho Public Utilities Commission approved an updated formula for determining the rates that regulated utilities must pay small power producers for the power produced at plants that generate up to 10 megawatts of renewable energy.

The energy crisis of the late 1970s prompted Congress to pass the **Public Utilities Regulatory Policies Act**, or **PURPA**. Its purpose is to encourage the development of renewable energy technologies as alternatives to burning fossil fuels or building new power plants.

PURPA requires that electric utilities offer to buy power produced by qualifying small power producers or **cogenerators**. Some cogenerators, such as J.R. Simplot Co., produce power as a byproduct of timber or potato processing or other types of manufacturing. State commissioners set the rate that utilities must pay small power producers for the power they generate. That rate, called **"avoided cost rate,"** is to be equal to the cost the electric utility avoids by not generating the power itself.

Last May, the commission agreed to a request by current and potential

PURPA developers to extend the contract length of PURPA projects from five to 20 years and increase the size of projects that can qualify for PURPA rates from one megawatt to five megawatts. (One megawatt, or one million watts, is enough energy to power about 750 homes.)

After the commission expanded both the size limit and contract length for PURPA projects, **Idaho Power Co., Avista Utilities** and **PacifiCorp** asked the commission to delay the signing of any new PURPA contracts until the commission could examine whether the formula the commission used to determine the rates utilities were required to pay PURPA developers were still reasonable. The data used in the formula to determine the rate was, until this order, based on 1995 data. The power companies alleged that the longer contract lengths and increases in project size would lead to purchase prices for the utilities that exceed their avoided cost.

The commission granted a petition for reconsideration filed by the regulated utilities and agreed to examine the reasonableness of the 1995 rates.

Fuel costs are a substantial component of the avoided cost rate. In establishing a fuel component for generators that don't use fossil fuels – such as wind, solar or anaerobic digesters – a starting fuel price is computed that reflects the average of natural gas prices during the previous calendar year at Sumas, Wash, a major trading hub for natural gas. To account for inflation, that starting fuel price was then increased at a 6 percent rate over the life of the contract. The new formula adopted by the commission today decreases that annual escalation to 2.6 percent. There is also an adjustable component of avoided cost rates that, on July 1 of each year, captures changes in natural gas fuel costs.

"It is the commission's belief that in issuing this order we are establishing a platform for avoided cost pricing that is reasonable and will appropriately reflect the avoided cost of each utility into the future," the commissioners said.

Responding to a petition for reconsideration by J.R. Simplot Co. and Earth Power Resources, Inc., the commission agreed to **increase the size** of projects that would be eligible for PURPA rates from 5 megawatts to 10 MW. The 5 MW limit would prevent many wind, geothermal and biomass projects from qualifying, Simplot argued. More than 60 percent of Idaho Power's capacity from PURPA developers is provided by projects between 5 and 10 MW in size.

The commission agreed that allowing larger-sized projects, combined with the new 20-year contract length, will make it more possible for PURPA developers to recover their capital costs and that "a larger eligibility size will encourage development of alternative energy projects."

PacifiCorp-Utah Power

Based in Salt Lake City, Utah Power, a division of Portland-based PacifiCorp, provides electricity in eastern Idaho. It is the third largest electric utility in Idaho.

Utah Power relies more heavily on thermal generation facilities than any other electric utility in Idaho.

In 2000, the average UP&L residential customer used 12,599 kWh of electricity, a 3.6 percent decrease from the 13,069 kWh average in 2000. This figure averages residential customers with electric space and water heating with those who do not use electricity for these uses.

January 31, 2002

BPA CREDIT TO RESULT IN AVERAGE 44 PERCENT CUT

Case No. PAC-E-02-1, Order No. 28946

Residential customers of PacifiCorp-Utah Power will see an average reduction in their power bills of 44 percent as the result of an agreement between the Bonneville Power Company and Utah Power approved by the Idaho Public Utilities Commission.

The **BPA credit**, which goes into effect Feb. 1, also benefits small-farm customers of PacificCorp, who will see their bills go down by an average of 63 percent.

"This reduction to residential customers will be a huge benefit in southeast Idaho where there are a lot of total electric homes," said Commissioner Dennis Hansen. "It will also be a tremendous relief for farmers." The BPA credit comes as a result of extensive negotiations between BPA and state commissions from Idaho, Montana, Oregon and Washington.

The **1980 Northwest Power Act** required that residential and small-farm customers in the Northwest share in the benefits of the federal hydroelectric projects located in the region.

PacifiCorp's previous exchange agreement with BPA expired in 2001, but a new settlement negotiated by the state commissions and BPA is substantially higher than historical levels.

"There were multiple negotiation sessions," said Paul Kjellander, president of the Idaho commission. "We are grateful that these benefits could come at a time that offsets some of the increases we've seen," Kjellander said.

The commission expressed its appreciation to BPA "for its acknowledgement that the benefits of the federal Columbia River power system should be spread to all residents of the Pacific Northwest."

Utah Power has also filed an application with the commission to recover $38 million in power supply costs the company incurred during the last two

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Pacificorp
dba
Utah Power & Light
1407 West N.Temple
Salt Lake City
Utah, 84116

801-220-2000
(SLC)
208-852-1916
(Preston)
208-356-7366
(Rexburg)

Number of Customers
= 56,434

years. The company requests to recover the amount over two years, $27 million in the first year and $11 million during the second. That, along with a proposal to adjust customer rates to bring them closer to the actual cost of serving each customer class, is still under review by the commission. Hearings will be conducted on those matters.

If the commission were to grant Utah Power recovery of the full requested amount, bills would still average 8 percent lower than current amounts, according to the company.

April 12, 2002

COST RECOVERY DOES NOT VIOLATE MERGER AGREEMENT

Case No. PAC-E-02-1, Order No. 28998

PacifiCorp's application seeking recovery for costs the utility incurred buying power on last year's high-priced wholesale market is not a violation of a two-year rate moratorium the commission imposed on the company before approving its merger with ScottishPower in 1999, the commission ruled.

While this order said PacifiCorp is not violating the moratorium, commissioners stressed that the order does not mean PacifiCorp will be able to pass any or all of those expenses to customers. That matter is yet to be decided by the commission.

Before it approved the merger between PacifiCorp and ScottishPower in 1999, the commission required the newly merged utility to meet **46 merger conditions**. The first two of those conditions were that rates would not increase as a result of the merger and that ScottishPower "shall not seek a general rate increase for its Idaho service territory effective prior to January 1, 2002."

On Jan. 2, 2002, PacifiCorp filed an application with the commission seeking authority to recover about $38 million in extraordinary power supply costs it incurred from Nov. 1, 2000, through Nov. 1, 2001.

Timothy Shurtz, a Firth resident and an intervenor in the PacifiCorp cost recovery case, asked the commission for a clarification of the above merger condition. Shurtz questioned whether PacifiCorp's case to recover power supply costs is "an attempt to avoid the moratorium agreed to in inducing this commission to accept the merger then being considered." Shurtz petitioned the commission for a clarification of Merger Condition No. 2.

The majority on the commission said PacifiCorp's application does not violate the merger condition because rates did not increase during the two-year rate moratorium.

Commission President Paul Kjellander and Commissioner Marsha Smith said PacifiCorp "did not seek any increase in rates to be effective before 2002, therefore the company has fulfilled that condition." Further, the costs PacifiCorp seeks to recover are not merger-related, the two commissioners said, but are attributable to "extraordinarily high wholesale market prices outside the control of the company."

Commissioner Dennis Hansen dissented, saying that PacifiCorp's attempt to recover costs that were incurred during the rate moratorium "undermines the benefits of this agreement to the ratepayers."

"I believe ratepayers would not have supported the merger condition if they had known that PacifiCorp could petition this commission for reimbursement of costs incurred during the rate moratorium freeze," Commissioner Hansen said.

UTAH POWER
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June 6, 2002

PACIFICORP ALLOWED SOME RECOVERY; BPA CREDIT KEEPS RATE DOWN

Case No. PAC-E-02-1, Order No. 29034

PacifiCorp will be allowed to implement a two-year surcharge on its southeast Idaho customers to recover about $22.7 million in power supply expenses incurred from Nov. 1, 2000 through Oct. 31, 2001.

The total amount of power supply costs incurred by the company attributable to its southeastern Idaho territory was originally $49 million. However, $11 million of those costs were incurred before PacifiCorp's authorized period of deferral began on Nov. 1, 2000. In January of this year, PacifiCorp applied for recovery of the remaining $38 million.

Settlement negotiations between PacifiCorp, commission staff, the Idaho Irrigation Pumpers Association and Monsanto Company resulted in a settlement of $25 million. "When viewing the company's total power purchases, the settlement represents a 50/50 sharing between customers and the utility," the commissioners said.

However, the actual surcharge will recover $22.7 million as the result of the **acceleration of a credit** allowed customers when PacifiCorp merged with ScottishPower in 1999. The last two years of the four-year credit were accelerated to provide a benefit of $2.3 million to customers. Accelerating the credit is not loss of the credit, commissioners emphasized, but ensures customers will get the full value of the credit earlier.

Commissioner Dennis Hansen dissented on portions of the order dealing with the confidential nature of the settlement discussions.

This order completes a case that was handled in two parts.

Last February, PacifiCorp's residential and small-farm customers received a **credit from the Bonneville Power Administration** that resulted in decreases of about 44 percent to residential bills and 63 percent for small-farm customers.

The second part of the case dealt with, among other issues, PacifiCorp's request to recover $38 million in power supply costs. The **negotiated settlement** of a $22.7 million surcharge, combined with the BPA credit, has the net effect of reducing average residential rates about 28.2 percent from customer bills a year ago. Small-farm customers net a 28 percent decrease from a year

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ago, including the BPA credit, and will get an additional 11 percent next year. Large commercial customers net a 34 percent decrease from last year's rates while some customers in commercial and industrial classes will receive, at most, a 4 percent increase.

The drought and the volatile energy market, combined with the failure of one of the company's major generation units at Hunter, Utah, caused the company to be short on power supply. That forced the company into the high-priced wholesale market to purchase power. After shareholders had borne $11 million of those costs, the company asked the commission to begin a deferral period. The deferred amount of about $38 million was considered in this case.

PacifiCorp customers, unlike any others in the Northwest, actually received some benefit as the result of last year's drought and extremely high wholesale market prices.

That same volatile market compelled BPA, also short on power, to offer PacifiCorp a **cash settlement** instead of providing PacifiCorp the power it was due from BPA. PacifiCorp's quick response resulted in an additional $11.5 million for PacifiCorp's Idaho customers. No other Idaho electric utility was able to secure this additional benefit for its customers because the market prices for power fell and BPA withdrew the settlement offers. "The settlement came about as a result of the very same market conditions that were responsible for PacifiCorp's unprecedented level of purchased power expenses," the commissioners said.

The commissioners cautioned PacifiCorp's customers to not become accustomed to the size of the BPA credit. "This exchange benefit is temporary and customers would be wise to explore options" to reduce their future use, the commissioners said. "In doing so, they will be prepared when the BPA credit no longer includes the additional financial benefits that resulted from the volatile wholesale market."

While supporting the portion of the application that includes the BPA credit, nearly all of the PacifiCorp customers attending **public hearings and workshops in Rigby and Preston** opposed the power purchase cost recovery portion of the company's application.

In written comments and in oral testimony, many customers expressed the view that executives of the utility promised not to raise rates for three to five years after the 1999 merger of PacifiCorp with ScottishPower.

At hearings, customers repeatedly referred to a cabin meeting with PacifiCorp executives and elected officials during which utility officials allegedly made significant promises regarding future treatment of expenses.

"However, because these promises from the cabin meeting were never made known to the commission and placed in the merger case record, they were not considered then, and we are legally unable to consider them now," the commissioners said. The commission, as a quasi-judicial body, must confine its decisions to the record produced at hearings. "Failing to do so, we violate procedural due process of law," the commissioners said.

"While this commission can appreciate the anger of the company's customers, we are bound by previous orders and the evidence of record that these decisions rested upon."

The company could not have anticipated the unprecedented price spike in the wholesale market in late 2000 through mid-2001, the commissioners said. "Similar expenses were incurred by every utility in the Western interconnection, both public and private, including Idaho Power Company and Avista Utilities."

In his dissent, Commissioner Dennis Hansen said the negotiated settlement is not specific enough about how much in costs are allocated to the failure of the Hunter unit, nor does the settlement provide details on any other costs that led to the agreed upon amount of $25 million.

"I cannot, in all honesty, determine that this settlement is in the public interest when so very little information was provided to the commission regarding what constitutes the settlement," Hansen said. "I believe this settlement amount was taken out of the hands of the commission and I cannot accept this proposal on blind faith."

Hansen also stated that PacifiCorp could have done more to reduce the deferred amount, such as interrupting service to its largest customer, Monsanto Company.

In their majority opinion, Commission President Paul Kjellander and Commissioner Marsha Smith said the settlement does not attempt to assign blame or allocate a specific percentage of cost sharing for Hunter. "The settlement provides a negotiated recovery figure and not a road map to determine how the figure was determined," the majority opinion stated.

"Settlement negotiations of parties, under commission procedural rules are, by their very nature, confidential," commissioners said.

Many who testified at the hearings criticized the negotiations that resulted in the proposed settlement as a process that failed to provide an opportunity for public participation. Even though the settlement was completed before the public hearings, the commission reserved making judgment as to the reasonableness of the settlement until after the public hearings concluded.

Those parties involved in the settlement negotiations, including representatives for irrigators, Monsanto and commission staff, supported the final result. One intervenor, Tim Shurtz, did not sign the stipulation.

Representatives of the Idaho Irrigation and Pumpers Association said, "The agreed upon net recovery of approximately $22.7 million in excess power costs is reasonable and appropriate given the risks of a less favorable result, the Irrigators limited resources, and in light of other settlements reached in other jurisdictions on this issue."

Commissioners did agree with customers that the company failed to provide adequate notice of its application, leaving some with little time to prepare for hearings. Commissioners noted that the company did not comply

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with a commission rule to provide each customer with individual notice through bill stuffers or a comment page with the customer's bill.

The final settlement also includes modifications to the revenue requirement from irrigation customers that bring those customers closer to their actual cost of service. Because the cost-of-service study came at the same time as the BPA credit, irrigation rates will not increase even though the revenue requirement from that class of customers is higher.

A **"rate mitigation adjustment,"** that is also part of the settlement, reduced the impact of the power supply cost by spreading recovery over two years.

October 25, 2002

IPUC UPHOLDS VIOLATION, BUT DECREASES PENALTY

Case No. PAC-E-02-1, Order No. 29136

The Idaho Public Utilities Commission unanimously upheld its earlier finding that PacifiCorp violated a customer service rule by not providing customer notice of a proposed change in rates. But the commission agreed with the company that the penalty the commission affixed – a $20 per customer credit – is excessive and contrary to state statute. Instead, the commission assessed a civil penalty of $10,000 to be paid to the State of Idaho General Fund.

Rule 102 of the commission's **Utility Customer Information Rules** require gas, electric and water utilities to give each customer notice, usually through a bill stuffer, when the utility applies to the commission for a change in rates or charges. PacifiCorp contended the rule did not apply because its January application to recover $38 million in power supply costs was not a permanent rate increase, but only a temporary surcharge.

The company said it did issue press releases and took other steps to notify customers once public hearings on PacifiCorp's application were scheduled in Rigby and Preston last May.

On June 7, the commission accepted a settlement that allowed the company to recover $22.7 million of the original $38 million requested. The commission also ordered the company to credit each of its 55,000 Idaho customers $20 for failure to notify customers according to commission rules.

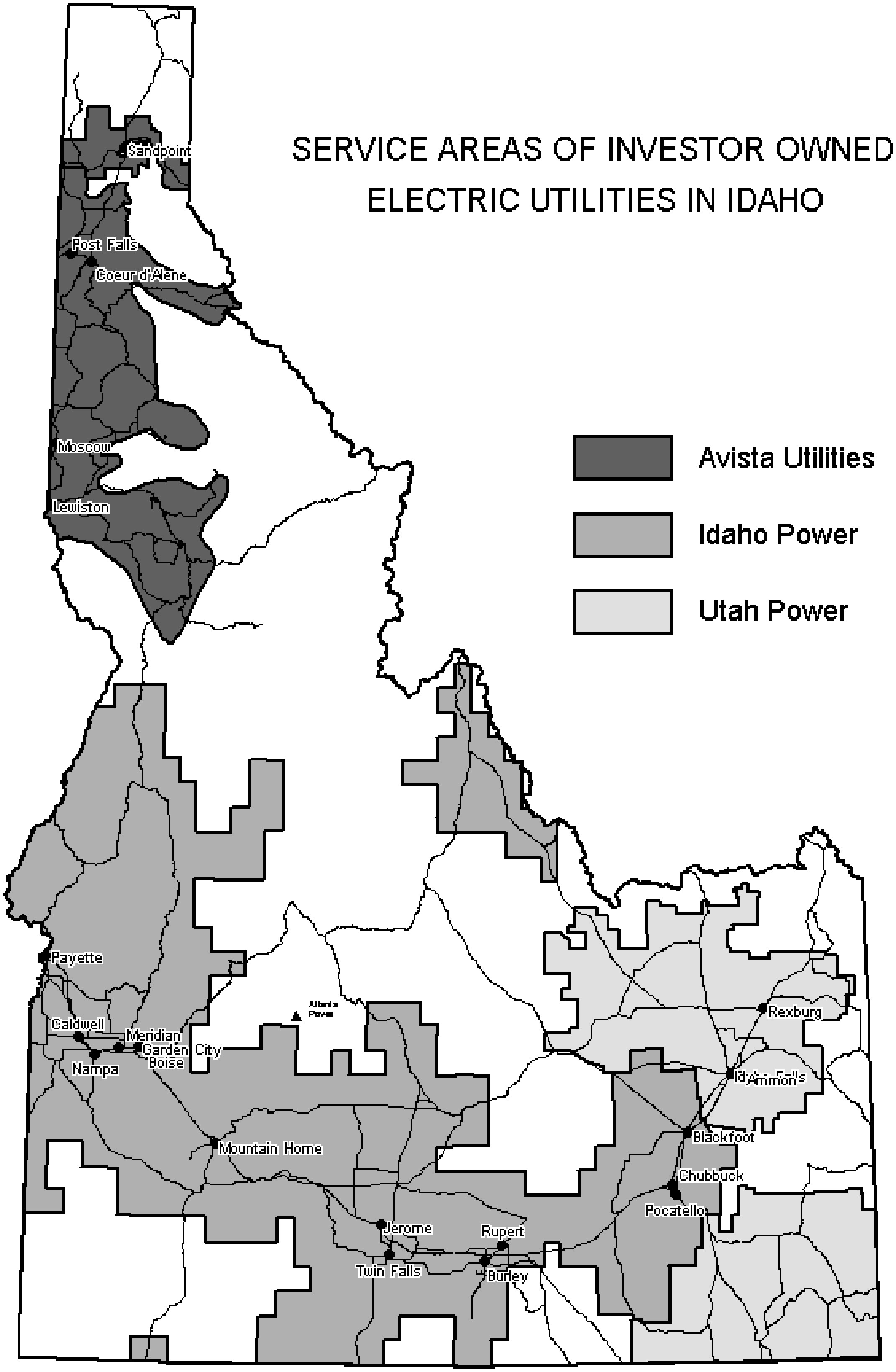
PacifiCorp filed a **motion for reconsideration**, contesting the applicability of the rule and the amount of the customer credit. The commission granted reconsideration and conducted a hearing in September. At that hearing, PacifiCorp officials testified providing each customer notice is difficult because multiple communications to customers are interpreted as multiple rate changes. The commissioners disagreed. "Customers should not be kept uninformed merely because a case is complex and difficult to describe and the notice may be misunderstood," the commissioners said. "It is the company's responsibility to craft a clear description of the filing so that customers can distinguish between what is proposed and what is approved."

The company argued that the rule regarding customer notice is ambiguous when it comes to cases that are not permanent rate increases or annual rate tracker cases. The commission's order responds by saying, "As a general practice, we find that when a company perceives some definitional ambiguity or a similarity to cases where notice is required, it should err on the side of providing notice."

PacifiCorp further argued that because it issued press releases and met with customer groups, there was significant public comment on its filing and participation in the two public hearings. However, that still does not justify lack of notice, commissioners said. "This commission will not countenance an attempt by the company to establish a principle that it may disregard commission rules if it can later demonstrate a lack of injury or harm to the public." Many customers complained, the commission said, of not being given enough advance notice to prepare for the Rigby and Preston hearings. And: "The overall tenor of written comments submitted in this case instead, if anything, indicates that the public was confused as to what was at issue."

The commission agreed with the company that the $20 credit to each customer, which would amount to about $1.1 million, was excessive when compared to past penalties against utilities for similar violations. Commission rules allow a $2,000 penalty for each rule violation. The commission determined to assess a civil penalty of $2,000 for each month from the time the company applied in January until public hearings in May, or $10,000.

"While the company contends that the commission should regard the company's failure to provide Rule 102 notification notice as simply a good faith mistake, it is troubling that the company appears to discount the value of individual notice, and the value of getting information with the monthly bill," the commissioners said.


SERVICE AREAS OF INVESTOR OWNED
ELECTRIC UTILITIES IN IDAHO
Avista Utilities
Idaho Power
Utah Power
Sandpoint
Post Falls
Coeur d'Alene
Moscow
Lewiston
Payette
Caldwell
Meridian
Garden City
Boise
Nampa
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Jerome
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Rexburg
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Blackfoot
Chubbuck
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