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

2004 Average Number of Customers/Avg. Revenue/kwh

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

336,204 Residential Customers/$0.0629
66,047 Commercial Customers/$0.0497
107 Industrial Customers/$0.0409

Idaho's electricity rates are among the lowest in the nation

Avista Utilities

2004 Average Number of Customers/Avg. Revenue/kwh

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

92,076 Residential Customers/$0.0623
14,949 Commercial Customers/$0.0673
524 Industrial Customers/$0.0424

2004 Average Number of Customers/Avg. Revenue/kwh

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

PacifiCorp/Utah Power

47,372 Residential Customers/$0.0434
6,775 Commercial Customer/$0.0576
5,396 Industrial Customer/$0.0349

Electric Utility Case Reviews

Idaho Power Company

May 25, 2004

IDAHO POWER GRANTED RATE INCREASE

Case No. IPC-E-03-13, Order No. 29505

Idaho Power Company was granted an average 5.2 percent increase in electric rates effective June 1, 2004. However, the yearly power cost adjustment order, also released the same day (Case No. IPC-E-04-9, Order No. 29506), means that some customer classes, including irrigators, got either decreases to their overall bills when compared to last year or much smaller increases.

A two-year surcharge imposed on irrigation and small-commercial customers resulting from the 2000-2001 energy crisis expired earlier in May. That means that while irrigation customers received a 13.95 percent increase to base rates, their overall rate declines by 5.8 percent.

In October 2003, Idaho Power asked the Idaho Public Utilities Commission to approve an average 17.7 percent rate increase and later revised that request down to 14.5 percent. The company initially sought to increase its annual revenues by $85.6 million. The commission's May 15 order authorized the company to collect $25.3 million in new revenue, 5.2 percent more than current revenues. The commission approved a return on equity of 10.25 percent and an overall rate of return of 7.85 percent. The company sought a minimum 11.2 percent return on equity and an 8.334 percent overall rate of return.

The company later sought reconsideration from the commission on a number of issues. On July 13 (Order No. 29547), the commission granted the company $2.67 million in computational errors. That increased the company's new revenue to $28 million, increasing rates about another half-percent, to 5.8 percent, effective Aug. 1.

In that July order, the commission denied the company reconsideration on other issues and delayed a decision on its original denial of $11.5 million in income tax expense for which the company sought recovery.

On Sept. 28 ***(see press release page 19)***, the commission and the company reached two settlements that granted the company the $11.5 million in income tax expense (Order No. 29601), but also settled three other outstanding issues (Order No. 29600), which, when totaled, resulted in a $19.3 million credit given to customers over a two-year period. Settlement of all these issues would have a minimal impact on rates that would not be implemented until after the company's next power cost adjustment in June 2005.

Regarding the main rate decision of May 25, part of the increase is a $3.30 monthly service charge for residential and small-commercial customers, up from $2.51. The company requested $10.

To send a stronger conservation signal, the commission accepted Idaho Power's proposal to assess a higher rate for residential and small-commercial customers during June, July and August when power is most expensive. However, the commission implemented the higher rate only for electrical use of more than 300 kWh. The rate, which is 12.5 percent higher in the summer, should not apply to use under 300 kWh, the commission said, to allow for basic use such as for lighting and home appliances.

The annual power cost adjustment (PCA), also released May 25, is a yearly mechanism that increases or decreases customer rates to account for above-normal or below-normal costs of supplying power. Idaho Power's costs of supplying power depend on water levels (in a normal water year, Idaho Power generates 60 percent of its power from hydroelectric dams) and the cost of buying replacement power on the wholesale market or from other sources when hydro generation is short. Although another year of low water could have resulted in a slight increase in the PCA, the company proposed leaving the rate the same to avoid customers getting an increase in both the PCA and in the base rate during the same year.

The PCA was approved at the same time as the rate case to avoid confusion associated with rate changes. The base rate increases and the PCA adjustment for each of the major customer classes are as follows:

- The base rate increase for **residential** customers is 5.98 percent. Including the PCA, the increase is 5.4 percent. The company requested 19.9 percent. **The current average rate with PCA for residential customers is 5.78 cents per kWh. The new average rate is 6.09 cents.**
- For **irrigation** customers, the base rate increase is 13.95 percent. The company requested 25 percent. When the PCA is included, irrigators get an overall reduction of 5.8 percent. **Current average rate with PCA, 5.04 cents per kWh. New average rate, 4.75 cents.**
- **Small-commercial** customers, while getting an increase of 5.97 percent to base rates, end up with an overall increase of 1.5 percent due to the expiration of their two-year PCA surcharge. The company requested 21 percent. **Current average rate with PCA, 7.18 cents per kWh. New average rate, 7.285 cents.**
- **Large-commercial** customers (schools, larger retail stores) receive a base rate increase of 2 percent, but that is reduced to 1.7 percent with the PCA. The company requested 15 percent. **Current average rate with PCA, 4.25 cents per kWh. New average rate, 4.325 cents.**
- The base rate for **industrial** customers increases by 2.4 percent, but after the power cost adjustment the overall rate is a decrease of 5 percent. The company requested 13.9 percent. **Current average rate with PCA, 3.6 cents per kWh. New average rate, 3.42 cents.**

The rates apportioned each customer class are based primarily on the costs to serve that class.

The commission took a number of steps to encourage reductions in electrical demand. In addition to higher summer rates for residential and small-commercial customers, the order mandates a phase-in of time-of-use rates for industrial customers. Time-of-use rates give industries financial incentive to shift electrical use to off-peak hours. The commission ordered Idaho Power to submit a proposal for a conservation program with industrial customers. The commission also ordered a $1 million increase to a low-income weatherization fund, increasing current funding from about $225,000 to about $1,225,000. It also opened a new case to determine how to avoid financial disincentives to Idaho Power for participating in conservation programs.

Among the largest reductions the commission made to the company's request was an approximate $25.5 million reduction in rate base and an $18.8 million reduction in test year expenses for a number of items relating to salaries, pensions and incentive pay for Idaho Power executives and employees.

Commissioners expressed concern about the public perception surrounding benefits and employee bonuses paid by IDACORP, Idaho Power's parent company, at the same time customers were paying unprecedented electric rates. "It is difficult to explain why Idaho Power expected its ratepayers to pay extraordinary power supply costs while it simultaneously rewarded employees with bonuses," the commission said.

Four public workshops and five hearings, attended by about 350 citizens, were held throughout Idaho Power's service territory. The commission also received more than 500 written comments. There were several groups represented by attorneys in the case including the Industrial Customers of Idaho Power, the Idaho Irrigation Pumpers Association, the Northwest Energy Coalition, Community Action Partnership of Idaho, AARP and others.

The commission heard from many low-income and irrigation customers. Low-income customers and senior citizens asked the commission to consider current economic conditions before granting any increase. Irrigation customers said the company's proposed 25 percent increase to irrigation rates would have a severe impact of farms and agricultural communities. A number of customers expressed concern about letting a decade lapse since the last Idaho Power rate case, resulting in a proposed large rate increase and possible rate shock.

Many customers believed that areas of high growth should bear the brunt of the increased costs to serve Idaho Power's 100,000 customers added since the last rate case. Past commission efforts to attach higher rates or fees on new customers were overturned by the state Supreme Court in *Idaho State Homebuilders v. Washington Water Power and Idaho Public Utilities Commission* in 1984 and in *Building Contractors Association of Southwestern Idaho v. Idaho Public Utilities Commission and Coalition of Boise Water Customers* in 1996. In both cases, the court said higher fees or rates targeted to growth discriminated against new customers.

Irrigators argued that new customer growth, particularly in urban areas, caused increased costs to the company while the irrigation load did not change. Other parties to the case argued that irrigation rates should be even higher, noting that irrigators should pay anywhere from 29 percent to 47 percent more than current rates to fully meet the cost to serve irrigators. Some intervenors in the case complained that other rate classes subsidize irrigation customers.

The commission maintains that the major reason for the increased cost of service to irrigators is the rapidly rising cost of power during peak summer use, which is when irrigators use their power. However, the commission acknowledged that irrigators and other parties to the case "raised serious questions" regarding the accuracy of the cost of service studies and ordered the opening of a separate docket to evaluate cost of service issues.

The commission said the 13.95 percent increase for irrigators, while fair, is significant but unavoidable. "Even if the precise results of the of the cost of service methodology are discounted, the large disparity between those results and existing irrigation base rates shows that in a relative sense, the irrigation class does not pay its own way and other customer classes make up the difference," the commission said.

Many customers opposed increasing the residential service charge from $2.51 to $10 per month. Idaho Power maintained that costs other than billing and meter reading should be included in service charges, including a portion of the investment associated with distribution facilities. The commission said the charge should cover only metering reading and customer billing. The commission, approving an increase to $3.30, said the company's proposal would "dampen the incentive for customers to conserve energy," because all customers pay the charge regardless of the amount of energy used. Commission staff noted that residential customers with the lowest usage would see a 298 percent increase in bills with the company's proposal while the largest users would see an 8 percent increase.

The commission adopted a recommendation of the Community Action Partnership of Idaho to increase Idaho Power's funding level of Low-Income Weatherization Assistance from about $225,000 to about $1,225,000. In past years, the fund is depleted by mid-year. The commission said weatherization funds lower the amount of uncollectible bills and create permanent electric load reduction, benefiting not only those whose bills are lowered, but all Idaho Power customers.

September 28, 2004

IDAHO POWER, COMMISSION REACH SETTLEMENT ON ISSUES

Case No. IPC-E-03-13, Order No. 29601; Case No. IPC-E-04-9, Order No. 29602

The Idaho Public Utilities Commission today announced two separate settlements of issues arising out of the recently concluded Idaho Power rate case and the company's annual power cost adjustment.

The first settlement resolves a disagreement between the company and the commission over how income taxes should be expensed.

On May 25, the commission approved an average 5.2 percent rate increase for Idaho Power. The company requested 14.5 percent. After that May 25 order, Idaho Power asked the commission to reconsider the portion of the order that said income tax expenses Idaho Power can recover from customers must be calculated on an historic five-year average rather than on the statutory federal and state income tax rates. The effect of using the five-year average was to decrease Idaho Power's annual revenue requirement by $11.5 million.

The company used a new tax expense methodology that resulted in a $41 million refund in 2002 on taxes paid in prior years and pushed income tax expense to future dates. To minimize the future tax expense impact on customers, the commission ordered a five-year average of income tax expenses. Idaho Power petitioned for reconsideration, expressing concern that the Internal Revenue Service could challenge the five-year average causing the company to lose its ability to use accelerated depreciation for incomes tax purposes. If accelerated depreciation is lost, the company claimed, income taxes would be significantly higher and Idaho Power would be required to obtain additional financing. That could result in the company seeking to increase rates further to cover tax expense, the company claimed.

"Although we originally approved use of the five-year average, we are concerned about the uncertainty created by the resulting IRS challenge and the risks that litigation might pose to ratepayers, " the commission said. The benefits – including the company's use of accelerated depreciation, the potential for lower borrowing costs and the avoided litigation – outweigh the tax increase, the commission said.

Because the new rates from the rate case became effective June 1, rates to account for the $11.5 in additional revenue will not be adjusted until next year. For this year, between June 1 and next May 31, Idaho Power and the commission staff proposed a formula to compute and record monthly in a regulatory asset account an amount equal to the additional revenue that the company would have received using the statutory income tax rates rather than the five-year average. The total will then be included for recovery from customers when Idaho Power has its annual power cost adjustment process (PCA) next spring.

The second settlement agreement settles three outstanding issues, that, when totaled, will result in a $19.3 million credit given to customers over a two-year period.

The first issue involves a change in the accounting treatment associated with a 2002 income tax refund. That will result in a credit to customers of an undisclosed amount.

Customers will also receive credit for a portion of the $6 million to $7 million in additional power supply costs the company and ratepayers paid as a result of an equipment failure at the Valmy generation plant in Nevada.

Idaho Power jointly owns the Valmy plant with Sierra Pacific, a Nevada utility. The generator unit was out of service from June 26 through Sept 8, 2003. Because of the outage, Idaho Power was required to purchase replacement power at rates significantly higher than the costs for Valmy. Staff questioned whether customers should pay the above-normal costs for replacement power. In the settlement, both parties acknowledge that the outage was atypical and, in part, out of the control of Idaho Power.

In another matter related to the comprehensive settlement, staff and Idaho Power agreed to leave a PCA expense adjustment rate for growth at the current level of 1.684 cents per kWh. Idaho Power argued for a much lower expense adjustment while commission staff argued for a higher adjustment. The current rate of 1.684 cents is about the midway point between the commission's and company's recommended adjustments. The adjustment is credited against the amount of money the company is able to claim in its PCA due to growth in energy sales. During those years when Idaho Power has below-normal energy sales, the expense adjustment is added to the company's power costs.

Neither of the two settlements will impact customer bills until next June. One settlement results in an increase to base revenues for Idaho Power for $11.5 million. The second settlement results in a $9.65 million credit to Idaho Power customers over a two year-period for a total credit of $19.3 million. The impact on customer rates next spring is minimal.

January 2, 2004

COMMISSION OKs BENNETT MOUNTAIN PLANT

Case No. IPC-E-03-12, Order No. 29410

The Idaho Public Utilities Commission approved Idaho Power's application to build a 162-megawatt gas-fired power plant in Mountain Home.

The plant, to be operational by summer 2005, will be built to meet the company's peak electrical demands during June, July, August, November and December. Though the plant can be dispatched for use at any time, it likely will not be operational during non-peak periods.

The commission's order allows Idaho Power to include $44.6 million for recovery from customers in base rates after the plant is completed. However, costs for this plant were not included in the rate case mentioned above.

Anticipated costs in addition to the $44.6 million that cannot be quantified now can be included in base rates up to a cap of $54 million, but only after those costs are audited by the commission and found to be reasonable and prudent. Unknown costs include sales taxes, start-up fuel and construction change orders.

Boise-based Mountain View Power was selected from 11 bidders. Mountain View contracted with Siemens-Westinghouse Power Corporation to furnish all the labor, equipment and materials and to perform all the engineering and construction. Upon completion of the project and successful performance tests, ownership of the project will transfer to Idaho Power.

Commission staff calculated that the energy cost over the 30-year expected life of the plant to be $44.60 per megawatt-hour. The $44.6 million cost of the plant compares favorably to the $49 million cost of the 90-megawatt Danskin plant, also near Mountain Home, completed in September 2001.

Intervenors in the case included the Industrial Customers of Idaho Power and the Idaho Irrigation Pumpers Association. Advocates for the West, a nonprofit conservation law firm, filed comments in the case asking that the commission delay a decision and include the Bennett Mountain plant in the Idaho Power rate case. Advocates for the West further stated that Idaho Power has not adequately explored other options such as more effective peak-load management.

The commission denied Advocates' request to combine Bennett Mountain with the rate case because doing so would unnecessarily delay both cases. Further, a delay would cause Idaho Power to miss a key deadline that could have impacted the bid price.

However, the commission agreed with the thrust of comments from the Advocates, as well as comments filed by commission staff, that Idaho Power "must vigorously pursue" and implement alternatives other than new generation to meet customer demand. "We have not retreated from out belief that demand-side management and peak-load management programs offer viable alternatives to the incremental construction of peaking generation units," the commission said. "Programs or procedures that reduce critical peak hourly demand have great value to both ratepayers and the company."

The company estimates up to $11.6 million in transmission costs to connect the plant to the company's 230-kv transmission line four miles north of the plant site. The company did not seek recovery for those costs in this case. Williams Northwest Pipeline, whose pipeline is less than one mile from the proposed plant site, will supply the natural gas. A 3,400-foot pipeline connecting the plant to the Williams pipeline will be constructed. Fuel costs will be included in the company's annual power cost adjustment process as are other power supply expenses.

The plant site is an approximate 10-acre plot within the Mountain Home Industrial Park. The site, north of Interstate 84 and west of State Highway 20, is large enough to accommodate an additional generating unit if needed. The city has already issued a conditional use permit for construction of the plant.

March 16, 2004

COMMISSION, CUSTOMER GROUPS, IDAHO POWER REACH AGREEMENT

Case No. IPC-E-01-16, Order No. 29446

Various customer groups, Idaho Power Company and the Idaho Public Utilities Commission have reached a settlement regarding past trading activities involving Idaho Power and its former trading arm, IDACORP Energy, LP.

The settlement includes the payments of credits to Idaho Power customers that began in 2003 and will continue through 2005 totaling nearly $10 million.

Most of the issues in the settlement had to do with Idaho Power and IDACORP Energy (IE) trading, hedging and risk management practices during the height of the Western energy crisis of 2000-01.

Neither Idaho Power nor IE has been found to be guilty of the same trading practices engaged in by Enron and other traders in California. However, the Federal Energy Regulatory Commission in May of 2003 found that IDACORP failed to get IE registered as a trader before engaging in power trades that should have been pre-approved by FERC. The federal agency ordered IE to transfer $5.8 million in revenues it earned in wholesale trades to Idaho Power. That ensured ratepayers, not shareholders, of getting the benefits from the trades. At the same time, the IPUC launched its own investigation to determine whether more revenues are due Idaho Power customers from IE, which used Idaho Power transmission and other system resource benefits in its trades. The conclusion of that investigation resulted in an additional $4 million that will be credited Idaho Power customers. That results in the continuation of a $167,000 per month credit from Idaho Power customers' electric bills through December of 2005.

The Western energy crisis of 2000-01 led to unprecedented increases in the annual power cost adjustment for Idaho Power customers over the following two years. "In light of the manipulative strategies used by Enron energy traders and others in California, we have heard from many Idaho Power ratepayers who were understandably concerned that these high rates were attributable to improper transactions between Idaho Power and its energy trading affiliate, IE," the commission said. "Although Idaho Power cannot be held responsible for high rates resulting from the Northwest's multi-year drought or wholesale energy price volatility, we believe this stipulation appropriately compensates ratepayers for benefits received by IE."

The stipulation is the result of 12 meetings including representatives from the following customer groups: AARP, Industrial Customers of Idaho Power, Micron Technology, Idaho Irrigation Pumpers Association, J.R. Simplot Company, Idaho Retailers Association and Advanced Energy Strategies, Inc.

In June of 2002, IDACORP announced it was discontinuing IE's power trading business.

April 6, 2004

COMMISSION OKs IDAHO POWER IRRIGATION PROGRAM

Case No. IPC-E-04-3, Order No. 29462

The Idaho Public Utilities Commission has approved an Idaho Power program that pays irrigators who volunteer to turn off selected pumps during summer peak-use times.

The one-year pilot program is designed to help the company meet anticipated shortfalls in generation and decrease Idaho Power's overall energy costs which would, in turn, result in a potential savings to all of the company's customers.

Idaho Power hopes to get up to 50 metered service points of irrigators from each of four geographic areas to participate. Those who meet eligibility criteria for the program would agree to have the company install timers behind metered service points that provide power to pumps of at least 150 cumulative horsepower. When the company reaches critical peak demand periods during the months of June, July and August, the company would be able to shut off the pumps for up to four hours between 4 p.m. and 8 p.m. on Mondays through Fridays.

Irrigators can choose to be shut off for four hours each day for either one, two or three days per week. Those who choose to be shut for one four-hour period a week would have their billing demand charge credited by $1.75 per kilowatt of monthly peak demand. Those who choose two days per week would be credited $1.88 and three days, $2.

Idaho Power estimates the program will cost $294,750. Money to operate the program will come from the Energy Efficiency Rider that appears on residential, irrigation and commercial bills. For residential customers, the charge is 30 cents per month. For irrigation customers, the rider is $0.0003 cents per kWh, but not to exceed $15 per meter per month.

Idaho Power hopes to gain up to 50 metered service points from each of these four geographic areas: 1)Kuna, Melba and Nampa; 2) Mountain Home, Bruneau and Grand View; 3) Rupert and Paul; and 4) American Falls.

April 29, 2004

PUC SAYS GREEN TAG ISSUE NOT RIPE FOR JUDGMENT

Case No. IPC-E-04-2, Order No. 29480

The Idaho Public Utilities Commission denied an Idaho Power Co. request to issue an order declaring who owns the highly marketable "green tags," associated with PURPA energy projects owned by small power producers.

Green tags, or "renewable energy credits," are a currency that can be traded to individuals and entities wishing to support renewable energy. They are becoming more valuable as a growing number of states are starting to require their regulated utilities to buy or generate a certain amount of power from renewable sources. Because green tags are created by the states, their ownership is not addressed by the federal PURPA legislation.

Idaho Power asked the commission to determine who owns the green tags: PURPA project owners or the utility that contracts to buy the power from the project owners. Idaho Power proposed that the commission allow project owners to retain ownership of the green tags because that would encourage development of green resources. However, Idaho Power proposed to retain the "right of first refusal" to purchase the tags before project owners offer them to another buyer.

The commission's order says the matter is "not ripe for declaratory judgment," noting that neither the Federal Energy Regulatory Commission nor the state has given the commission authority to rule on the matter. The Idaho Legislature has not enacted renewable portfolio standards, has not created a green tag program and has not established a trading market for green tags.

Idaho Power has contracts with about 70 PURPA projects.

Since PURPA was enacted, regional organizations, such as the Bonneville Environmental Foundation, have been created to certify projects as "green energy compliant." Power projects found to be compliant are issued green tags that can be traded.

Idaho's other large electric utilities, PacifiCorp and Avista Utilities, filed comments in the case stating that the green tags are the property of the purchasing utility. The Bonneville Environmental Foundation, Northwest Energy Coalition and the Advocates for the West asked the commission to confirm that project owners own the green tags. Other small power producers who intervened in the case said the commission had no jurisdiction or authority to decide the issue.

Idaho Power claimed the tags represented a value to the utility because they have monetary value separate from the actual energy produced. Idaho Power claimed that if it were granted ownership rights to the green tags, the revenue from them could be used to lower energy costs to Idaho Power customers or be reinvested in the development of additional renewable resources in the state.

PURPA project owners contended keeping ownership of the tags benefits the state because the ability to sell green tags provides incentive from more renewable development. It also compensates owners for their projects' environmental attributes and rewards them for the risk they take to invest in and operate a renewable energy plant.

While the commission's order does not allow Idaho Power to include a right of first refusal provision in PURPA contracts, it does not preclude parties from voluntarily negotiating the sale and purchase of green tags. However, the price a regulated utility would pay for the green tags is not a PURPA cost that the utility can recover from ratepayers, the commission said. "Recovery of those expenses will be reviewed as all other non-PURPA costs," the commission said.

October 30, 2003

COMMISSION APPROVES WIND POWER CONTRACTS

Case No. IPC-E-04-2, Order No. 29479 and Case No. IPC-E-04-19, Order No. 29630

The Idaho Public Utilities Commission approved two major energy sales agreements from wind generators in 2004.

The first, between Idaho Power Co. and a Montana wind generating facility, had features not included in the utility's agreements with other small power producers who qualify for published contract rates under federal PURPA provisions.

The 20-year contract is with United Materials of Great Falls, Inc., a 9-megawatt wind facility in Montana.

The terms and conditions of this new generation of contracts have yet to be tested in a complaint proceeding, the commissioners said. "It remains to be seen whether this approach for purchases of … renewable energy is in the public interest." Because of those untested provisions, the commission emphasized that its decision "sets no precedent for our future regulation of such agreements," and does not preclude negotiating parties from challenging the reasonableness of such contract terms in future agreements.

Typically, small power projects that qualify under PURPA provisions are guaranteed a published rate that is set by the commission and based on the cost the regulated utility avoids by not having to generate the power itself or buy it from another source. But because the output of wind generation is unpredictable, Idaho Power included unique provisions in the contract that require United Materials to reimburse the utility when wind production falls to 90 percent or less of its promised delivery and Idaho Power has to pay more than the contract terms for replacement power. If the wind generation exceeds 110 percent of a month's estimated kilowatt-hours of generation, Idaho Power has agreed to pay United

Materials a market-based price for that surplus.

The power generated at United Materials of Great Falls is outside Idaho Power's service territory. Northwestern Energy, which operates in Montana, has agreed to schedule all energy deliveries from United Materials to Idaho Power over its transmission lines.

The second agreement is a 20-year sales contract with Montana-based Fossil Wind Gulch Park, LLC.

Fossil Gulch intends to construct and maintain seven 1.5-megawatt wind turbines about 3 ½ miles west of Hagerman. Idaho Power would purchase the power under the commission's established rates for PURPA projects.

The commission ordered that the current PURPA rate of about 5.5 cents per kWh be adopted, even though the rate is soon expected to increase to about 6 cents. "Although the avoided cost rates are likely to change in the near future, we find it reasonable to approve the agreement's terms based upon the published rates that we in place at the time the agreement was negotiated in good faith," the commission said.

The commission also said that all payments for prudent energy purchases made under the agreement can be allowed as prudently incurred expenses for later recovery from customers.

May 5, 2004

COMMISSION RELUCTANTLY ACCEPTS IDAHO POWER BIOMASS CONTRACT

Case No. IPC-E-04-5, Order No. 29487

The Idaho Public Utilities Commission accepted an energy sales agreement between Idaho Power Co. and Renewable Energy of Idaho, but not without some strong wording directing the utility to follow previous commission orders that specify how such sales agreements are to be priced.

Idaho Power sought commission approval of a 20-year contract to buy energy from a 17.5-megawatt generating facility that will produce power from wood waste and other renewable materials at the old Boise Cascade Plant near Emmett. Renewable Energy of Idaho plans to design, construct and operate the biomass facility.

Federal PURPA regulations require that utilities must buy power from qualifying renewable sources at a rate set by state commissions. Idaho limits the size of the projects that qualify for PURPA rates at no more than 10 megawatts. According to a commission order issued in 1996, rates for projects larger than 10 MW must be determined by using a specified cost model that determines a rate that is reasonable for the company, the renewable project and for customers. Instead of following that model, Idaho Power and Renewable Energy negotiated a contract based primarily on less certain forward market prices and recent Idaho Power contract purchases. Idaho Power claimed it did not have sufficient experience using the cost model and that Renewable Energy was under severe time constraints to get the project started before it would no longer be viable.

The commission ultimately approved the agreement because the rate negotiated, while a departure from approved methodology, is reasonable and the commission agreed that timeliness is critical to the project's success. The facility would dispose of waste forest materials that are immediately available, created as a result of Congress' Healthy Forests mandate.

The commission said the company's failure to follow commission-approved methodology is "both unacceptable and inexcusable," and emphasized this case sets no precedent for future cases. It warned Idaho Power that if it chooses to not abide by the methodology in future contracts, those contracts would be regarded as voluntary purchases rather than mandated purchases under PURPA and thus not subject to full cost recovery from customers.

Commissioners said if Idaho Power believes the methodology is no longer valid, "it is incumbent upon the company to make a filing with the commission and request changes."

Commissioners also did not want the project to fail because of the company's failure to follow previous commission orders. "What is persuasive in this case is the unfairness of holding the project hostage for the failure of the utility to follow" commission approved methodology, the commissioners said. "We regret that the company has placed Renewable Energy, staff and the commission in this position."

October 13, 2004

IDAHO POWER SUBMITS LONG-RANGE POWER PLAN

Case No. IPC-E-04-18, Order No. 29614

The Idaho Public Utilities Commission received a plan from Idaho Power outlining how the company intends to serve increasing electrical demand from its growing customer base over the next 10 years. The commission had not decided on whether to accept the plan by press time for this annual report.

Idaho Power developed the Integrated Resource Plan (IRP), over a year's time and included input from industrial and irrigation customers, the environmental community, the Legislature, the governor's office and commission staff.

Regulated electric utilities are required to file an IRP with the commission every two years. The commission then decides whether to acknowledge the plan as one that meets the commission's requirements for IRPs. Acceptance of an IRP does not mean that new generation projects or resource acquisitions will be approved when companies petition the commission to include the projects in rates. All projects are evaluated for their necessity and prudency at the times they are proposed.

Idaho Power's IRP places a greater emphasis on conservation and demand reduction. There are nearly equal amounts of generation planned from renewable resources and the more traditional thermal generation.

The company plans to increase its power supply by about 800 average megawatts. The company's average amount of electricity need to serve its customers is 1660 average megawatts. The company also plans on increasing its capacity (the amount of electricity needed to serve its customers at peak-use times) by another 940 megawatts. Its current peak load capacity (reached in the summers of 2002 and 2003) is 3000 megawatts. The long-term plan calls for the following portfolio:

- 76 MW from demand response programs. These are programs where customers can choose to reduce or shift their electricity use. They include an air conditioning cycling program and an irrigation peak-clipping program.
- 48 MW from energy efficiency programs such as manufactured home incentives, home energy checkups and industrial and irrigation efficiency efforts.
- 360 MW from wind-powered generation
- 100 MW from geothermal-powered generation
- 48 MW from combined heat and power facilities. These are typically located at industrial sites that produce power as a byproduct of their manufacturing process.
- 88 MW from natural gas plants
- 62 MW from distributed generation and purchases of electricity on the wholesale market. Distributed generation are typically small-power facilities that generate at or near the site of ultimate consumption as opposed to most electricity, which is generated at a remote site and transported by long-distance transmission lines to the consumer.
- 500 MW from coal-fired generation.

The company is also proposing a near-term action plan of steps to be taken before the company files its next IRP in 2006. By this fall the company plans to have issued bids for 200 MW of wind resource. In 2005, the company plans to take bids for 12 MW of combined heat and power and 100 MW of geothermal generation.

October 15, 2004

COMMISSION SEEKS COMMENT ON LOST REVENUE CALCULATION

Case No. IPC-E-01-34, Order No. 29612

The state Supreme Court's decision to allow Idaho Power to recover "lost" revenue from an irrigation load reduction program in 2001 now leaves it up to the commission to decide how that revenue should be computed and to determine an amount.

The irrigation load reduction program was implemented during the summer of 2001 due to the drought and record-high wholesale market prices at the time. To reduce the need for Idaho Power to go to the expensive wholesale market, the utility paid irrigators to reduce their electric use. Irrigators were paid 15 cents per kWh saved. That prevented the company from having to go to the market to buy power that, at the time, was predicted to be 30 cents per kWh during peak irrigation summer months.

When the commission adopted the buyback program 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 determined the company should recover $74 million from customers in direct costs paid to irrigators, but denied the company's request for $12 million in "lost revenue," money the company claimed it would have earned from irrigators had the buyback program not been in place.

At the time, the commission said the load reduction program was the prudent, if not the required, action to take in response to the 2000-01 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."

The commission further stated in an August 2002 order, "The commission finding did not guarantee that Idaho Power was entitled to recovery of alleged reduced/lost revenue that resulted from this program. Rather, the commission merely recognized that the issue of recovery of these amounts would be considered."

However, the Supreme Court ruled that the commission's use of the word "may" meant that the commission did intend to allow Idaho Power to recover the lost revenue from customers.

The company originally calculated that the irrigation load reduction program would cause it to lose $11,587,179 in revenue and $428,008 in carrying charges through March 31, 2002. Because the commission did not believe the company was entitled to the lost revenue, it did not conduct its own investigation as to whether the company's proposed $12 million is reasonable.

At press deadline for this report, the commission was seeking comments from interested parties as to how the amount should be calculated and what it should be. When the program was proposed, the Idaho Irrigation and Pumpers Association, although supportive of the concept of lost revenue, urged the commission to make adjustments that would have reduced the calculated amount by several million dollars.

November 19, 2004

COMMISSION ADOPTS IDAHO POWER-EAGLE SETTLEMENT

Case No. IPC-E-04-4, Order No. 29634

The Idaho Public Utilities Commission accepted a settlement between Idaho Power Co. and the City of Eagle regarding the construction of a new 138-kV transmission line from the Eagle substation to a new substation in Star.

The settlement approves 1) a route for the transmission line; 2) a plan to bury a portion of the distribution line at the city's expense and 3) a method to pay for the buried distribution line that includes the city increasing its franchise fee for electric service from 1 percent to 3 percent.

To pay the approximate $300,000 cost to bury the distribution line, Idaho Power consents to the city's request to increase Idaho Power's franchise fee from 1 percent to 3 percent. The fee is a city fee imposed on Idaho Power. Idaho Power pays the fee by levying an increase equal to the franchise fee on the company's customers who live inside city limits.

The 3 percent fee is intended to remain in place until Dec. 31, 2010, at which time with the city agrees to "take all actions necessary" to bring the fee back to 1 percent. Once the cost of burying the distribution line on Eagle Road is reimbursed to Idaho Power, the city may use the fee to defray the cost of burying additional distribution lines within the city.

Idaho Power filed a complaint against the city last February after the city twice rejected Idaho Power applications for a conditional use permit seeking permission to build the transmission line. The company asked the commission to resolve the dispute, maintaining its current facilities in Eagle and Star are "severely strained" and vulnerable to a decline in service quality by next summer.

In September, the commission conducted a technical hearing followed by a public hearing. During the public hearing, members of the Eagle City Council urged the commission to consider an alternative route to those proposed by Idaho Power that would avoid residential areas, not adversely affect commercial values along a bypass around the city and would preserve scenic views along State Street, Jackson Square and the gateway intersection of the bypass and Eagle Road.

Commissioners noted the importance of public input in resolving the issue. "Although this process has been difficult and contentious at times, this case is another example of the importance of a public hearing," commissioners said. "In particular, it was the testimony received at a public hearing that precipitated investigation of the new alignment proposed."

November 22, 2004

COMMISSION SETTLES IDAHO POWER, SMALL-POWER PRODUCER ISSUES

Case No. IPC-E-04-8, Order No. 29632

The Idaho Public Utilities Commission issued an order defining the parameters of contracts between Idaho Power and developers of small-power wind and geothermal projects.

Two operators of wind power projects and another operator of a geothermal project in Cassia County filed complaints with the commission early in 2004 alleging Idaho Power is requiring contract terms that are contrary to federal PURPA provisions.

A complaint was filed last March by U.S. Geothermal, which owns the 15-megawatt Raft River Geothermal Power Plant being built in Cassia County. A separate complaint was filed by Bob Lewandowski, operator of a wind project east of Boise, and Mark Schroeder, who is developing a wind project in the Hagerman-Bliss area. The complaints were consolidated by the commission into one case.

Over recent months, the commission has started to receive more applications from wind and geothermal projects seeking to qualify for PURPA rates. These types of projects pose new challenges for the commission, regulated utilities and small-power producers. A major question regarding wind projects in particular is the reliability of their output and if the commission should treat such projects as “firm” sources of power. Firm power sources are more valuable than non-firm, less predictable sources of power. Up until recently, most all PURPA projects in Idaho have been small hydro facilities or co-generation projects at potato processing plants or lumber mills where electricity is produced as a byproduct of the manufacturing process.

Essentially, the small-power producers objected to Idaho Power’s contract provisions in three major areas.

1) Idaho Power proposed to pay other than the commission-set posted rates when the output from the complainants’ projects is less than 90 percent or more than 110 percent of projected output. Idaho Power claimed that when output is less than 90 percent it must find power from other sources that can be more expensive. When output is more than 110 percent, Idaho Power said it might have to sell the energy in the surplus market or reduce output at a more economic generation plant.

The commission, by a 2-1 vote, agreed to the 90-110 performance band, but allowed the developers more opportunities to revise their output estimates thereby allowing them greater likelihood of staying within the performance band. The commission also lessened the severity of the financial penalties QFs (Qualifying Facilities) would receive for falling outside the performance band.

Commissioner Marsha Smith dissented on the performance band issue. The incentive for all small-power producers is to provide all they power they can, she said. “They need to be paid to stay in operation and if they do not produce, they do not get paid. The banding proposal would operate as a penalty, not an incentive,” Smith said.

Commissioners Paul Kjellander and Commissioner Dennis Hansen said performance bands are necessary because both parties of a contract must have reciprocal and enforceable obligations. To qualify for the commission’s posted rates, QFs have an obligation to meet at least 90 percent of their commitment. If QFs over-deliver there is also a consequence to the company, the majority said. If unplanned for and not easily integrated, the energy may, as suggested by the company, have to be sold in the surplus market or other more economic resources of the company ramped down, the commissioners said.

Idaho Power had proposed allowing developers to revise their output estimates three times during the first year of operation and then once every two years thereafter. The commission ordered that QFs initially provide Idaho Power with one year of monthly generation estimates followed by estimates every three months.

Further, the commission revised the financial penalties Idaho Power proposed if QFs fail to meet production estimates. Idaho Power proposed that QFs that fail to deliver at least 90 percent pay the difference if the price Idaho Power pays for replacement power (which would be priced at 85 percent of market price) is greater than the monthly contract price. Idaho Power agreed to cap the penalty at 150 percent of the contract rate. Further, Idaho Power wanted to require that the QF pay for the power Idaho Power would have to purchase to meet the shortfall if the price of that power exceeded the contract price. The commission accepted the 85 percent of market price provision but removed the shortfall penalty.

2) The complainants objected to Idaho Power’s metered energy test as a method of determining whether a project qualifies under the 10 MW limit the commission places on the size of small-power projects to qualify for PURPA rates. Under commission rules, rates for projects larger than 10 MW are determined on a project-specific basis. Idaho Power said the 10 MW capacity is exceeded if a QF meter reads greater than 10,000 kWh per hour. US Geothermal argued capacity should be based on average annual energy delivered rather than an hourly measure because its output will vary from 8 MW in the peak of summer to over 12 MW in winter. If limited to a 10-MW turbine, U.S. Geothermal contends that its Raft River plant could not deliver close to an average of 10 MW per year.

The majority on the commission ruled that the 10 MW capacity limit should remain, but that Idaho Power's proposed metered energy test is "operationally too restrictive." Instead, the commission ordered that QF generation be measured on a monthly basis, rather than hourly. To qualify for PURPA rates, a QF must demonstrate that, under normal or average design conditions, the project will generate at no more than 10 average megawatts in any given month. The commission also capped the maximum monthly generation qualifying for payment.

Commissioner Smith dissented, saying capacity should be determined by an annual average. Idaho Power is protected by contractual provisions that provide a maximum monthly capacity amount and is not obligated to purchase excess deliveries, Smith said. "This is nothing more than the status quo that has been available to all legitimate resources," she said.

3) The developers objected to an Idaho Power provision that allowed it to terminate its QF contracts if Idaho allowed deregulation at the retail level and other parties were able to sell electricity in Idaho Power's service territory. Under that scenario, Idaho Power argued, it would be unable to fully recover its PURPA contract costs. The commission unanimously agreed to not allow Idaho Power to terminate contracts if deregulation occurs. "We will not permit Idaho Power to terminate QF contracts for reasons other than the default of the QF," the commission said.

Avista Utilities

September 9, 2004

AVISTA ELECTRIC, GAS RATE INCREASES ANNOUNCED

Case No. AVU-E-04-1, Interlocutory Order No. 29588; Case No. AVU-G-04-1, Order No. 29590

The Idaho Public Utilities Commission approved an overall 1.9 percent revenue increase in electric bills for Avista customers and an overall 20.6 percent increase in gas bills. (Avista later petitioned the commission for reconsideration on some issues, which are detailed in the press release below.)

These increases are the combined result of three commission cases dealing with changes in 1) permanent base rates for Avista's gas and electric customers and 2) temporary surcharges on both gas and electric bills that vary annually depending on weather conditions and wholesale prices for electricity and gas.

In the electric rate case, Avista originally requested a $35.2 million increase in revenue and, after input from commission staff, revised that to $31.1 million. The commission eventually approved $24.7 million. The commission approved a 10.4 percent return on common equity. The company requested 10.9 percent.

In the gas case, Avista originally requested a $4.75 million revenue requirement and, after input from commission staff, revised that to $4 million. The commission eventually approved $3.3 million.

In February, Avista applied to the commission to increase its permanent base electric rates by 24.1 percent and its permanent base gas rates by 9.16 percent. At the same time, Avista proposed a reduction in its temporary power cost adjustment (PCA) surcharge for electric customers. Combining Avista's proposed base rate increase with its proposed power cost adjustment decrease resulted in an overall proposed increase to Avista electric customers of 11 percent. After several months of analysis and technical and public hearings, the commission today ordered an overall electric rate increase of 1.9 percent.

Electric rates

While the overall electric increase for all customer classes is 1.9 percent, the increase for a residential customer using the company's average of 941 kilowatt-hours per month is about $4 per month or 7.1 percent. General service or commercial customers get an overall reduction of 6.7 percent and large commercial customers a 1 percent reduction. Large industry received a 6.2 percent increase. Rates for each customer class are based on the costs to serve each class. Today's commission order brings all rate classes within 10 percent of cost of providing service.

The new base electric rates increase Avista's earnings by $24.7 million, while the reduction in PCA rates decreases revenue by $20.33 million. The net increase, also counting a $1.2 million reduction in a conservation rider, results in a net increase of about $3.18 million or 1.9 percent. The base rate increases announced today are the first since 1999.

The PCA is a rate adjustment mechanism that annually increases (through a one-year surcharge) or decreases (with a credit) customer rates to account for above normal or below normal costs of supplying power. Costs of supplying power are dependent primarily on the cost of buying power on the wholesale market. While the base rate includes the costs of everyday operations, the power cost adjustment surcharge covers the always variable cost of energy.

The deferral balance in Avista's PCA account was accumulated primarily during the 2000-01 energy crisis when wholesale electric rates reached unprecedented levels. At its height, the deferral account was at $78 million. This order sets that account at just under $15 million. Avista had sought to recover $26.2 million from customers in its PCA deferred account, but the commission rejected about $11.26 million in expenses the company incurred purchasing gas for its Coyote Springs II gas-fired generating plant. The plant was not operational at the time and the fuel purchased was ultimately sold back into the market.

Gas rates

On the gas side, the commission's orders combine both a base rate change (the company's first in 14 years) and the 14.2 percent increase in the annual purchase gas cost adjustment, or PGA.

The commission adopted a 6.38 percent revenue increase in the company's permanent base rate after the company had originally requested 9.16 percent. In July, Avista requested a 14.2 percent PGA increase to account for rapidly increasing costs in the price of wholesale gas. The commission made both adjustments effective today to prevent customers from experiencing two gas rate adjustments.

With the combined increase, gas rates for a residential customer using the company's average of 73 therms per month will increase by $12.84 per month, or about 21.4 percent.

The permanent base rate change approves $3.3 million in additional gas revenues for a total revenue requirement of $55.23 million, a 6.38 percent revenue increase.

The PGA - the 14.2 percent increase - is a temporary gas surcharge or credit based primarily on the wholesale price of gas. Money collected in the PGA account goes to pay gas suppliers and, unlike changes in the base rate, does not increase Avista's earnings.

A continuing increase in the wholesale price of gas led to Avista's PGA filing. The commission approved an increase in Avista's weighted average cost of gas from 44.9 cents per therm to 55.7 cents. Because the wholesale gas market is volatile, the commission directed Avista to file for an out-of-period decrease if forward commodity prices decline by 5 percent or more.

Avista's northern Idaho territory includes about 110,000 electric customers and 61,800 natural gas customers.

November 24, 2004

COMMISSION DENIES AVISTA RECONSIDERATION ON MOST ISSUES

Case No. AVU-E-04-1, AVU-G-04-1, Order No. 29638

The Idaho Public Utilities Commission denied Avista Utilities' request for reconsideration of the commission's earlier decision to deny the company recovery for a major gas transaction and for construction cost overruns of the Boulder Park generation project in Spokane. The commission did allow some computational corrections sought by Avista that will not have an immediate impact on rates.

On October 8, the commission approved an overall 1.9 percent increase in electric rates for Avista customers and a 6.38 percent in gas rates. The company had sought an overall 11 percent increase in electric rates a 9 percent increase in gas rates.

As part of that rate case, the commission denied Avista authority to recover from its customers a total of $4.77 million, which was one-third of Idaho's share of an Avista purchase of natural gas to fuel the utility's Coyote Springs 2 combustion turbine. The commission also denied the utility authority to recover $2.6 million in costs attributable to construction overruns for the Boulder Park generation project.

On, October 29, Avista petitioned for reconsideration on both those issues. The commission's order is final. Aggrieved parties may appeal to the state Supreme Court.

Because the Coyote Springs 2 combustion turbine was not operational by the time the gas was to be delivered, Avista was forced to sell the gas back into the market at a loss and had to go to the electric market to buy replacement power.

Avista argued the gas purchase, known as Deal A, was prudent given what the company knew at the time and that the purchase fell within the company's risk management guidelines. The utility also argued that the transaction should be allowed because its affiliate, Avista Energy, was not a party to the transaction. In its original order, the commission rejected a similar $6.5 million gas purchase, known as Deal B, partly because the transaction was with Avista Energy.

The commission, in denying reconsideration, said the Deal A "transaction both in length (36 months) and financial exposure was unprecedented for Avista and was accompanied by little supporting analysis and paper trail."

Although Avista's affiliate was not a counter-party to the Deal A transaction, Avista Energy brokered the deal, the commission said. "Thus, contrary to Avista's contention, Deal A hedge losses cannot be viewed separate and apart from any Avista Energy involvement."

The commission said the nature of the Deal A transaction exposed Avista customers to risk that, while more appropriate for its unregulated subsidiary, was too much of a risk for the regulated side of the company. "Deal A was highly irregular and apart from any other transactions made by Avista. The fact that the company failed to purchase gas with the same kind of long-term deals for its gas customers that it did for its electric customers, we find, also demonstrates the company's inconsistency," the commission said.

Potlatch, a forest products company and large customer of Avista, filed a Cross Petition for Reconsideration regarding the Deal A transaction, arguing that the commission should have disallowed the entire purchase, not just one-third. Avista's decision to lock-in the price for 36 months was a gamble on the price direction of the natural gas futures market, an unprecedented move for Avista, Potlatch argued.

The commission disagreed, stating that while both the Deal A and Deal B transactions were objectionable, they were not expressly prohibited by commission order or established protocol. "It is a grey area, not black and white," the commission said. "The commission has a joint obligation to the utility and its customers," and has the authority under Idaho Code to assess the reasonableness of the company's actions, the commission said.

Avista called the commission's attention to some miscalculations in determining the losses attributable to Deal A that, in total, increase the loss recovery for Avista by $163,098. That amount will be calculated into Avista's power cost adjustment next year.

Regarding Boulder Park, the commission said customers should not be liable for most of the cost overruns on the generation project, which, at $31.9 million, was 53 percent higher than the projected $21 million. The commission allowed a 15 percent contingency for cost overruns. Washington customers of Avista also are assigned some of the cost. Idaho's share of the disallowance should be $2.6 million, the commission said. The company argued that the disallowance should not exceed the 10 percent of final project costs recommended by commission staff, or $1.1 million.

The commission found that Avista should be held to a higher standard than that recommended by commission staff. "Ratepayers, we found, should not be asked to pay for what we continue to find to be a company learning experience," the commission said.

Avista also petitioned for reconsideration of adjustments made by the commission to the company's pension costs. The correction, allowed by the commission, results in a $46,411 increase in the company's electric revenue requirement and an $11,422 increase in the natural gas revenue requirement. The impact on rates is negligible.

PacifiCorp-Utah Power

January 12, 2004

PUC APPROVES RATES, CHANGES TO IRRIGATION PROGRAM

Case No. PAC-E-03-14, Order No. 29416

The Idaho Public Utilities Commission approved changes in the amount of the credit irrigators receive for participating in Utah Power and Light's (PacifiCorp) irrigation load control credit rider program. The commission also approved some procedural changes designed to streamline the enrollment process and encourage greater participation.

Under the program, irrigators are paid credits for volunteering to shift their electrical use from super-peak hours to light-load hours during the four-month irrigation season. Power is more expensive during those hours of the day when it is in most demand. By curtailing use during peak hours or shifting use to hours when demand is less, both the utility and its customers save money.

During last year's first season for the program, 207 irrigators with 403 metered irrigation sites participated, resulting in a shifting or curtailing of 21 megawatts during the irrigation season. The irrigators who participated represented about 12 percent of UP&L's irrigation load in its southeast Idaho territory.

The credit approved by the commission is as follows:

- June, $1.68 per kilowatt shifted or curtailed.
- July, $2.24 per kW
- August, $2.19 per kW
- September, $0.96 per kW, to be prorated through September 15.

The Idaho Irrigation and Pumpers Association filed comments in the case. The organization does not agree with the pricing method UP&L uses to determine the credit, but did not oppose the changes because it did not want to hold up implementation of the 2004 program.

Currently, the credit is 70 percent of the difference between the expected super-peak price and off-peak market prices. UP&L calculated a 30 percent discount due to uncertainties in predicting the amount of load shifted, the level of load control equipment failure, failure of customers to shift load and other factors.

The pumpers association contends UP&L is focusing solely on projected market prices and not taking into account other program benefits, including the cost the company avoids by not having to depend on other resources for power supply.

The commission ruled that the current credit is reasonable for now but ordered the company to file a report in December this year that evaluates both the 2003 and 2004 irrigation seasons to assess the uncertainty factors claimed by UP&L.

The irrigation credit program is the result of a commission order issued in June of 2002 that directed UP&L to develop a load control program designed to reduce the company's power supply expenses by preventing it from having to go to the sometimes volatile wholesale market to meet customer demand. That June 2002 order allowed PacifiCorp to recover $22.7 million in power supply expenses incurred by the company during the 2000-01 period when wholesale electric prices reached record levels.

June 8, 2004

COMMISSION APPROVES PACIFICORP SETTLEMENT

Case No. PAC-E-03-5, PAC-E-04-2, Order No. 29518

Power rates for residential, commercial and small-farm customers of PacifiCorp (Utah Power) in southeast Idaho will decrease slightly effective June 8, according to an order from the Idaho Public Utilities Commission.

The order consolidates two cases PacifiCorp had before the commission. The first sought a 16-month surcharge to recover tax audit payments and the second requested an adjustment in the exchange credit that residential and small-farm customers receive from the Bonneville Power Administration.

The order approves a negotiated settlement of the issues in both cases. Participants in the settlement discussions included PacifiCorp, commission staff, the Idaho Irrigation Pumpers Association and the City of Firth.

Residential rates will decrease 1.7 percent for residential customers, while commercial customers will see about a 10.8 percent decrease. Irrigation customers get a 0.3 percent decrease. The only customer classes that will get increases are 226 large-power general service customers, who get a 3.6 percent increase, and four high voltage customers whose increase will be 2.9 percent.

Without these two cases, rates for all classes would have decreased by a greater amount, an average 5 percent. As part of the settlement, PacifiCorp agreed to not apply for a general rate increase that would become effective before the 16-month surcharge expires on Sept. 16, 2005.

"Such a commitment is not insignificant when one recognizes, as staff did, that the company has filed general rate increases in all five of its other state jurisdictions within the last two years and is prepared to do so in Idaho without an approved stipulation," the commission said.

"The rate effect of the proposed settlement for Idaho customers and irrigators is a prolonged period of rate stability," the commissioners said, noting rates for irrigation customers will not have increased during two irrigation seasons.

In 2002, the commission approved PacifiCorp's request for a two-year power cost surcharge to be added to base rates to collect $22.7 million the company owed other power suppliers as a result of the 2000-01 Western energy crisis that resulted in unprecedented increases in the wholesale cost of power. That surcharge was set to expire today. PacifiCorp requested an extension of 16 months to recover about $4.2 million. Most all of that amount is Idaho's portion of income tax payments the company made following an IRS audit of the company's 2002 and 2003 income tax statements. The remaining amount – about $200,000 – is for a projected under collection of power surcharge costs through June of this year.

The commission ruled that tax expenses are a legitimate cost of doing business, even though "aggressive filing" sometimes results in audits. "The aggressive filing of taxes by the company, assuming its tax positions are both reasonable and supportable, benefits both the company and its customers to the extent that it is successful in reducing its overall tax liability." However, the commissioners stated recovery for tax purposes should be handled differently than through the power cost adjustment process, which is designed to recover excess power supply costs. "We expect the company, in its next rate case, to propose a different method for the regulatory recovery of such expense," the commission said.

Also this year, the company filed an application with the commission to reduce the size of the credit customers get from the Bonneville Power Administration because the company has paid out $5.7 million more in credits than it received from BPA.

The BPA markets electricity at cost from 31 federally owned dams as well as some non-federal dams in the Northwest. 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 in the form of a credit to electric bills.

After discussions with the Idaho Irrigation Pumpers Association and commission staff, PacifiCorp proposed to reduce that shortfall by one-third each year over a three-year period, resulting in a reduction of $1.9 million each year. That would eliminate the current shortfall. To match the amount PacifiCorp credits its customers over the next three years with the amount it projects to receive from BPA, the company proposes to reduce the credit an additional $597,000 during each of the three years. The total proposed annual reduction for the next three years would be about $2.5 million. By spreading the reduction over three years the impact on customers is eased.

With the BPA credit adjustment, residential customers will see a reduction in the credit from 2.5 cents per kWh to 2.33 cents. Small-farm customers will see their credit reduced from the current 4.24 cents per kWh to 3.93 cents.

Overall, the settlement benefits all parties, the commission said. "The proposed settlement, which we find to be fair, just and reasonable, allows the company reasonable recovery of tax audit payments over an extended period; it allows amortization without carrying charges of the BPA credit overpayments; and it includes a general rate moratorium commitment from the company, all accomplished without a significant increase in customer rates."

November 10, 2004

PUC, PACIFICORP NEARING AGREEMENT ON MULTI-STATE JURISDICTION ISSUES

Case No. PAC-E-02-3

As of press deadline for this report, the Idaho Public Utilities Commission was seeking comments from Idaho customers of PacifiCorp on a proposed resolution of a longstanding process on how to allocate costs to serve customers in the utility's six state jurisdictions.

After years of negotiations, interested parties in all the affected states have submitted a uniform protocol to address the cost issues. The protocol must gain approval from the state public utility commissions of each state involved.

In 1989, Pacific Power & Light merged with Utah Power & Light to create PacifiCorp. That merger brought Idaho's customers of Utah Power & Light into PacifiCorp.

Since the merger, each of the six state commissions in PacifiCorp's territory has apportioned costs of generation to customers using differing methods. Cost recovery problems today are the result of states adopting varying methodologies that do not result in full cost recovery, according to PacifiCorp. That leads to uncertainty in financial markets about whether the company will be able to recover the costs of investment in capital improvements and additions. Absent resolution of these issues, it is difficult for the company to make adequate investment in new resources given concerns about the risk of cost recovery. The need for agreement has become more critical in recent years with the rapid growth in customer demand in PacifiCorp's service territory.

In what has come to be known as the Multi-State Process, staffs from state commissions, including Idaho, as well as industrial customers and consumer organizations, such as Monsanto and the AARP, have been negotiating for several years toward a more uniform method of cost allocation

PacifiCorp contends that ratification of this agreement will provide the company assurance that it will have a reasonable opportunity to recover prudent investments in new generation and transmission facilities and required improvements to existing facilities.

A significant challenge in the negotiations has been how to fairly allocate more expensive thermal resources and less expensive hydro resources across PacifiCorp's entire system. Most of the generating resources in PacifiCorp's western region of Washington, Oregon and California are hydroelectric dams while the eastern region of Idaho, Utah and Wyoming is more dependent on thermal resources, such as coal and natural gas.

Part of the proposed agreement is a “hydro endowment,” that reflects the differences in cost attributed to the former Pacific Power & Light states of Oregon, Washington, California and part of Wyoming.

In the near term, through 2008, the proposed cost allocation methodology results in a 2 percent higher revenue requirement for Idaho. The results beyond 2008 are more favorable to Idaho because future hydro relicensing costs would be assigned to Washington and Oregon.

Workshops explaining the company’s petition were held in October in Preston and Rexburg. The commission accepted comments from the parties of record through Nov. 23 and from the public through Dec. 6.

Generic Electric Cases

August 16, 2004

COMISSION CONSIDERING PROPOSED CUSTOMER RELATIONS RULE CHANGES

Case No. RUL-U-O4-02, Order No. 29573

The Idaho Public Utilities Commission agreed to accept a petition from the Idaho Community Action Network to re-examine some utility customer relations rules.

The commission agreed, by a 2-1 vote, to enter into a negotiated rulemaking process, which allows all interested parties, including utilities, to participate. The commission emphasized that agreeing to enter into negotiated rulemaking does not mean that all or any of ICAN's proposed changes will be adopted. Rules imposed on utilities by the commission must ultimately be adopted by the Legislature.

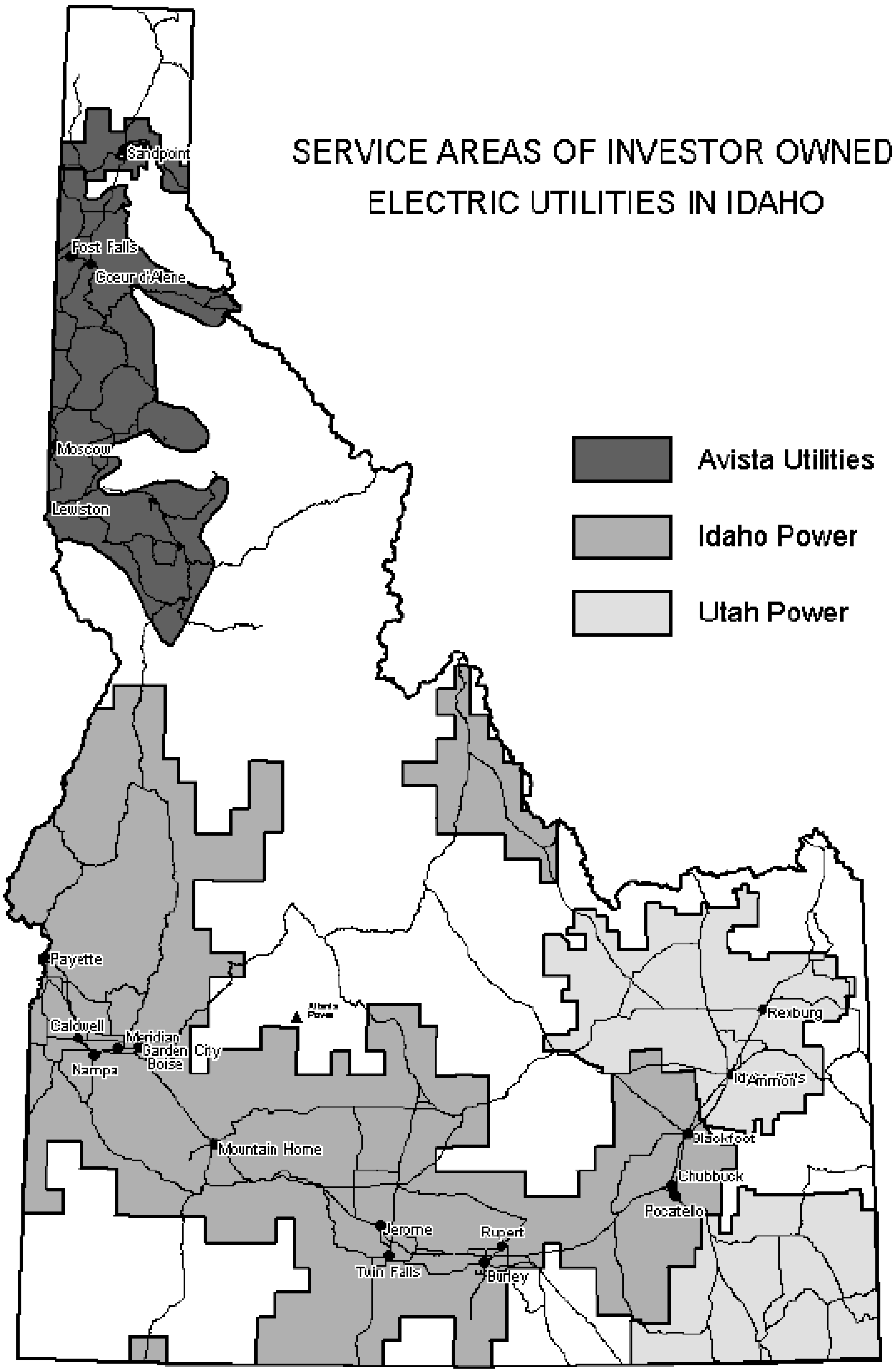
ICAN proposes that the three-month winter moratorium – the December through February period that utility customers with children, elderly, disabled or ill residents, can defer payment of utility bills – be expanded to also include November and March. During the moratorium, utilities are forbidden to disconnect customers who qualify for the moratorium. However, when the moratorium ends, the past due utility bills must be paid.

ICAN also seeks:

- to extend the period during which customers are protected from disconnection due to serious illness or medical emergency from the current 30 days to 60 days and allow the medical exemption to remain in place to up to one year;
- to increase the minimum number of days required to provide advance notice of the intent to disconnect service from the current 7 to 14 days;
- and require disconnect notices to include information on the winter moratorium and provide translation of those and other notices in a number of languages.

Commissioner Dennis Hansen dissented from the majority, saying he was comfortable with the rules in place and noted that some or all of the changes could result in increased costs to all customers. Commissioner Marsha Smith agreed with Hansen that the current rules may be adequate but said the commission should be open to considering possible improvements.

The commission is conducting workshops and opened a comment period as part of the negotiated rulemaking process. The commission can adopt rules as "pending rules," but they are not accepted as permanent rule changes until adopted by the Legislature.


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
Mountain Home
Jerome
Twin Falls
Rupert
Burley
Pocatello
Chubbuck
Blackfoot
Ammon
Rexburg