ELECTRICAL POWER IN IDAHO

Avista Utilities

2016 average number of customers/average revenue per kilowatt-hour

330,699 residential customers/$0.09605

41,785 commercial customers/$0.09613

1,342 industrial customers/$0.06085

Idaho Power Company

2016 average number of customers/average revenue per kilowatt-hour

440,362 residential customers/$0.1029

88,561 commercial customers/$0.0772

121 industrial customers/$0.0563

Rocky Mountain Power

2016 average number of customers/average revenue per kilowatt-hour

62,615 residential customers/$0.1064

9,339 commercial customers/$0.0910

628 industrial customers/$0.0658

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Settlement reached in Avista rate case

Avista's electric rates increased by an average of 2.6 percent on Jan. 1, 2017 after the utility reached a settlement with Commission staff and other parties.

The company had originally requested a 6.3-percent increase. The most significant adjustment to the company's proposal was to move $4.5 million in net expenses for the Palouse Wind project from base rates to the annual Power Cost Adjustment process.

The move reduced the economic burden imposed on Idaho ratepayers by 10 percent. The settlement also set the residential basic charge at $5.75 per month, down from $6.25 the company had requested.

In June 2017, Avista asked for approval of a two-year plan calling for rate increases in 2018 and 2019.

The company said the request was driven by ongoing investments in its plants and technology in addition to increased costs of providing power to its customers.

A tentative settlement agreement was reached in late September. If approved by the Commission, the settlement would increase electric rates by an average of 5.6 percent in 2018 and 2.3 percent in 2019, while increasing the basic monthly service charge by 25 cents, to $6. The company's original proposal called for an average increase of 7.9 percent in 2018 and 4.2 percent in 2019, along with the 25-cent increase to the service charge.

Commission deems prudent Avista's energy efficiency expenses

In June, the Commission determined that nearly $10 million Avista spent on energy efficiency programs in 2014 and 2015 was prudently incurred and therefore could be recovered through an energy efficiency rider paid by the 125,000 northern Idahoans who receive electric service from Avista.

The programs, which include educational outreach and incentives for weatherization measures, saved 31,081 megawatt-hours (MWh) over the two-year period, just meeting the company's goal of 30,996 MWh.

Commission approves changes to several surcharges

The Commission approved modifications to four annual billing mechanisms in September that affect customers who receive electric service from Avista.

The changes took effect Oct. 1, and the overall impact to residential customers was a 2-percent increase, or $1.73 on the monthly bill of the average residential customer using 910 kWh per month.

Here's a look at those billing mechanisms:

Fixed Cost Adjustment

This mechanism is modified annually in order to allow a utility to recover any fixed costs that are lost

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and conservation by ensuring that the utility will recover its fixed costs even if energy sales decline. In requesting Commission approval to increase the FCA by 3 percent, the maximum allowed, Avista said revenue fell short of expenses by approximately $6.5 million in 2016 due to an abnormally warm winter as well as savings from its energy efficiency programs.

As a result of the change, a residential customer using an average of 910 kWh in a month would see an increase of $2.56 on the monthly bill.

Power Cost Adjustment

This mechanism allows Avista to modify its rates annually when its costs of generating and purchasing electricity to serve is customers do not equal the revenue recovered through rates.

Since power supply costs were lower than expected in 2016, the PCA approved in September is expected to refund customers approximately $7.3 million.

That equates to a decrease of $2.03 on the monthly bill of the average residential customer using 910 kilowatt-hours per month.

Residential and Small Farm Energy Credit

The result of an agreement between the utility and the Bonneville Power Administration, this credit passed through to customers the benefits of the federal Columbia River hydropower system.

The change approved in September lowered the bill of the average residential and small farm customer by 0.2 percent. That equates to a savings of 16 cents on the monthly bill of the average residential customer using 910 kWh.

Energy efficiency rider

In September 2017, the Commission approved an increase to the Energy Efficiency Rider for Avista's electric customers.

The change took effect Oct .1, leading to an increase of $1.37 on the monthly bill for a residential customer using 910 kWh.

Adjusted with Commission approval, this surcharge allows a utility to recover the costs incurred providing energy efficiency services to its customers, and to match future revenue with expenses budgeted for energy efficiency programs.

In 2016, Avista's energy efficiency programs were underfunded by nearly $10 million. The primary reason for the deficit was a non-residential lighting program that exceeded its budget by $9 million.

The increase approved by the Commission is expected to boost revenue by approximately $3.9 million annually.

The surcharge is now assessed at 0.395 cents per kilowatt-hour used for residential service, up from 0.245 cents per kWh, while the surcharge will increase to 0.427 cents per kWh for general service customers, up from 0.271 cents per kWh.

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Programs funded by the rider will be scrutinized for prudency in a future proceeding. Expenses incurred through the programs must be cost-effective in order for the costs to be recovered through customer funds. Expenses not found to be prudent must be paid by shareholders rather than customers.

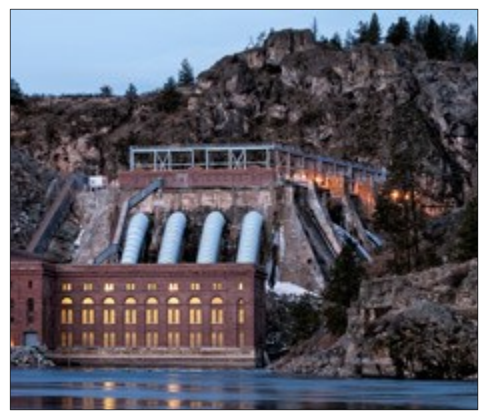
Avista files long-range planning document with IPUC

Avista expects conservation measures to offset more than half of its expected load growth over the next 20 years, according to a planning document filed with the Commission in August.

Though the need for new generation is expected, Avista's Integrated Resource Plan (IRP) also indicates its current generation resources will remain cost effective and reliable through 2036.

Regulated utilities are required to file an updated IRP with the Idaho Public Utilities Commission every other year. The IRP serves as a status report on a utility's ongoing plans to serve customers at the lowest cost and least risk over the next two decades.

Avista's 2017 IRP differs from its 2015 plan in several ways, including the anticipation of a slowdown in the annual growth rate, from 0.6 percent projected in the 2015 IRP to 0.47 percent; less reliance on natural gas-fired peaker plants; and a delay in the need for additional generation from 2020 until 2026.



The delay is due not only to lower than expected load growth but also recently signed contracts for hydropower, energy efficiency measures and the introduction of demand response programs that temporarily reduce the demand for energy.

While the preferred strategy outlined in Avista's 2015 IRP called for 557 megawatts (MW) of new natural gas generation, with the first facility projected to be in service by the end of 2020, the 2017 IRP calls for three new natural gas-fired plants with a combined capacity of 353 MW.

Those consist of a 204 MW natural gas-fired peaker plant to begin operation in 2026, a 102 MW peaker plant by the end of 2030 and a 47 MW peaker plant in 2034.

Peaker plants derive their name from the fact that they are utilized only during periods of peak demand for energy among customers. According to Avista, these peaker plants are more cost-effective because they provide a low-cost, flexible source for generation that allows the utility to efficiently incorporate intermittent power generation, such as wind and solar.

The company also plans to construct a 15 MW solar facility for its commercial and industrial customers, and is building two energy storage facilities that would provide a total of 2.5 MWh of storage.

Most of Avista's generation is through hydropower. The company owns and operates eight hydropower plants capable of generating 1,080 MW. The IRP calls for improvements to those plants that would boost capacity throughout the planning period.

Avista also recently signed long-term contracts with public utility districts to purchase hydropower gen-

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erated on the Columbia River. These contracts are capable of adding 165.3 MW to Avista's system. The company's thermal generation consists of five natural gas plants, a biomass facility and a 222-MW share of the output at the Colstrip coal plant. The Colstrip plant consists of four units located east of Billings, Montana.

Avista owns 15 percent of Units 3 and 4, which began operating in 1984 and 1986, respectively. Units 1 and 2 went into operation in the mid-1970s and are set for retirement by 2022. Avista said it analyzed a number of scenarios for Colstrip Units 3 and 4, including early retirement and significant reductions in generation.

But its preferred strategy calls for the two units to remain in service through the end of the planning period, as it remains a cost-effective and reliable source of power.

Avista's conservation efforts are expected to help meet 53.3 percent of the growth in load over the next 20 years. Current conservation efforts reduce retail loads by more than 12 percent. The IRP evaluated more than 8,700 options to reduce energy use.

These conservation and efficiency programs outlined in the IRP target not only customer consumption but also Avista operations. Plans call for upgrades to distribution equipment throughout its service area, as well as upgrades to boost efficiencies at Avista facilities. Overall, the company said it has identified 15,370 MWh of "achievable potential conservation" in Idaho.

Commission grants CPCN for transmission line in Wood River Valley

In September the Commission approved Idaho Power's application for a Certificate of Public Convenience and Necessity (CPCN) to build a new transmission line to serve the Wood River Valley.

In granting the request, the Idaho Public Utilities Commission said Idaho Power demonstrated that a redundant line is necessary to mitigate the risk to public health and safety of the valley's 9,000 residents.

The Wood River Valley is currently served by two substations fed by a single transmission line that links substations near Hailey and Ketchum. The need for a redundant transmission line in the valley was identified in the mid-1970s, and a previous CPCN was canceled in 1995 at the company's request.

The existing line was built in 1962 on wooden poles in mountainous terrain that can be difficult to access. It needs to be rebuilt, Idaho Power said, and a redundant line would also allow the line to be rebuilt without planned power outages.

In its CPCN application, Idaho Power said structure failure along the line could lead to an extended power outage. A redundant line would eliminate that risk, the company said.

In weighing the evidence, the Commission was persuaded that a major outage could last days or weeks due to access limitations along the current line that would hamper repair efforts.

Granting the CPCN is not a mandate to build the new line. In fact, the Commission's 18-page order notes that while Idaho Code requires a public utility to obtain a CPCN before constructing certain facili-

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ties or infrastructure, a CPCN is not required to extend lines, plant or system in an area already served by a utility.

The order also does not constitute approval of the cost of the project for ratemaking purposes.

Idaho Power is required to apply to the Commission in order to recover expenses associated with the project from its customers.

The project is expected to cost $30 million, with the company's proposed route calling for a transition from overhead lines to underground lines for a portion of the route leading into Ketchum.

IPUC approves Idaho Power proposal to lower efficiency surcharge

In April, the Commission approved an Idaho Power request to lower the energy efficiency rider paid by customers to fund conservation and efficiency programs. The move to lower the rider from 4 percent of monthly billed amounts to 3.75 percent led to a 22-cent decrease on the monthly bill of the average residential customer who uses 1,000 kWh per month.

The Commission also approved the company's request to refund customers $13 million in rider funds on June 1, reducing the impact of an increase to the Purchased Cost Adjustment billing mechanism.

Battery storage facilities eligible for contracts with Idaho Power

In July, the Commission determined that five proposed battery storage facilities were eligible for two-year, negotiated contracts with Idaho Power.

Plans call for the batteries to be charged with energy from nearby solar projects capable of generating 2.5 average megawatts, with the electricity dispatched to Idaho Power under the provisions of the Public Utility Regulatory Policies Act (PURPA).

PURPA requires electric utilities to purchase energy from qualifying independent power producers but gives state regulators authority to determine the contract terms for PURPA-eligible facilities.

In Idaho, PURPA projects larger than 100 kilowatts and powered by intermittent sources such as solar and wind are eligible for two-year contracts at a rate negotiated between the utility and the developer (IRP methodology).

The developer, Franklin Energy, contended that its storage projects should qualify for 20-year contracts at the more favorable published rate set by the Commission.

Franklin petitioned the Commission to reconsider its decision. In denying the request to reverse its decision, the Commission said Franklin failed to show that the final order was "unreasonable, unlawful, erroneous or not in conformity with the law."

Commission approves modifications to surcharges

In May, the Commission approved several cost adjustments for Idaho Power Company, leading to a rate increase of almost $2 on monthly bills of a typical residential customer as of June 1.

The Power Cost Adjustment increased by an average of 0.93 percent, leading to a 59-cent increase

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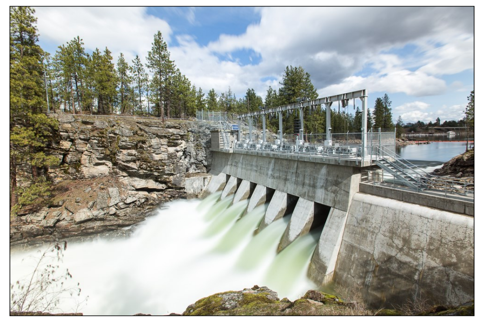
on the monthly bill for Idaho Power's typical residential customer using 1,000 kilowatt-hours., while a 1.29-percent increase to the Fixed Cost Adjustment led to an average monthly increase of $1.31.

The FCA is adjusted annually based on changes in energy use during the previous year by customers in two classes, Residential and Small General Service.

The mechanism separates revenues and energy sales, enabling the company to recover fixed costs incurred delivering energy to its Idaho customers even if energy sales decrease.

Without the FCA, the company would have a disincentive to help customers use less energy, or use it more efficiently, since there would be a loss of revenue as energy use declined.

In 2016, the company's residential energy sales decreased by 245,027 megawatt-hours (MWh) from 2015 levels, due in part to the growth of its energy efficiency programs.



That decrease in energy sales, combined with an increase in the number of customers in the Residential and Small General Service customer classes, left the company unable to recover its fixed costs for the year.

The FCA is now assessed at .6728 cents per kilowatt-hour (kWh) for Residential customers and .8576 cents per kWh for customers in the Small General Service class. The increase is projected to boost revenue by approximately $6.96 million, matching the amount under-collected in 2016.

The PCA allows Idaho Power to modify its rates each year to contend with fluctuations in the cost of serving customers due to factors beyond its control. Those factors include market prices for power, power transmission costs, revenue earned from selling surplus power and stream flows that diminish the hydropower generation on which the company relies.

The PCA is examined annually and adjusted up or down to either pay down already-incurred expenses if power costs exceed forecasts, or credit customers when expenses fall short.

The company said last year's power costs exceeded forecasts due in part to worse-than-expected water conditions. While stream flows have improved for 2017, the company expects to incur greater costs associated with solar and wind generation, and the unexpected collapse and abandonment of the Joy Longwall by the Bridger Coal Company.

As a result, the Commission approved raising the surcharge to .7361 cents per kWh, from .6187 cents.

Idaho Power seeks prudency determination for relicensing effort

In late 2016, Idaho Power asked the Commission to find that it had prudently incurred approximately $221 million in expenses related to a years-long effort to relicense the Hells Canyon Complex, the utility's largest hydropower facility. The company's application asks the Commission to deem those expenses prudently incurred and eligible for inclusion in customer rates in the future.

The Hells Canyon Complex provides more than one-third of the company's total generating capacity. Its license with the Federal Energy Regulatory Commission expired in 2005 and the company has been

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operating under an annual license issued by FERC since then. The relicensing effort began in 1991, according to the company, which led to filing for a new license in 2003. It estimates a new 40- or 50-year license will be issued after 2021.

Idaho Power proposal would reclassify net metering customers

In July, Idaho Power asked the Commission to approve its plan to overhaul its treatment of customers with on-site generation systems such as rooftop solar.

Idaho Power customers who generate their own electricity are currently included in the same rate class as traditional electric customers.

Since net metering customers can offset their energy consumption via their on-site generation resources, Idaho Power contends they do not pay their fair share for the operation and maintenance of the company's electric distribution system.

This shifts the financial burden of maintaining and running that system onto Idaho Power's traditional customers, creating a "wealth transfer from lower-income customers to higher-income customers," the company's filing states.

The company's proposed solution is to separate net metering customers into two distinct customer classes, Residential and Small General Service. The company said this would allow it to better understand those customers' impact on the distribution system.

The proposal applies to customers with on-site generation who sign up for new service on or after Jan. 1, 2018, existing net metering customers would "transition over some period of years" to one of the proposed new customer classes.

Idaho Power's proposal does not call for any changes to rates. Any such changes would be addressed in a future rate case.

Rocky Mountain Power submits plan for Commission acceptance

Rocky Mountain Power expects to transition away from coal over the next 20 years, according to the utility's Integrated Resource Plan (IRP).

The IRP outlines the utility's strategy for meeting customer demand for electricity through 2036.

It calls for the retirement of more than 3,500 megawatts of coal-fired generation, and for that generation to be replaced primarily with renewables such as wind and solar.

Efficiency measures, wholesale power purchases and two new natural gas facilities are also expected to help meet the demand for energy through 2036.

The Commission's acknowledgement of the IRP does not necessarily mean the projects highlighted will be completed, but rather that the utility has met its long-range planning requirements.

The first new natural gas-fired resource is expected to be added in 2029, a year later than anticipated in the utility's previous IRP, filed in 2015.

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The utility expects incremental energy-efficiency resources to provide a 2,077 MW reduction - enough to meet 88 percent of the forecasted load growth through 2026. The 2017 plan does not call for upgrades to coal plants in order to meet environmental regulations, a decision that will "save customers hundreds of millions of dollars," according to the company.

Instead, the IRP calls for 3,650 MW of existing coal capacity to be retired by the end of 2037.

The company expects to offset a portion of that lost generation with market purchases, although Rocky Mountain intends to construct two new natural gas facilities – a 200-MW frame simple cycle combustion turbine in 2029, and a 436-MW combined combustion turbine in 2030.

Over the life of the IRP, the preferred portfolio includes 1,313 MW of new natural-gas capacity. That is a reduction of 1,540 MW relative to the 2015 IRP.

Rocky Mountain seeks approval for wind and transmission projects

In July, Rocky Mountain Power asked the Commission to approve its plans to build or acquire four wind farms in Wyoming, upgrade or "repower" 13 existing wind facilities and improve its transmission system.

The projects are expected to cost $3.13 billion and would significantly boost the utility's capacity to generate wind energy.

Rocky Mountain Power asserted that the transmission projects are necessary in order to relieve congestion on the transmission system and improve the utility's ability to manage the intermittent load produced by wind.

Rocky Mountain requested that the Commission allow the projects' capital costs to be incorporated into customer rates, and for approval of Certificates of Public Convenience and Necessity (CPCN) for the new wind facilities and transmission improvements.

Rocky Mountain Power also asked the Commission to expedite the approval process to ensure that the projects meet deadlines for federal renewable electricity production tax credits. The wind projects must be in operation by the end of 2020 in order to achieve the full benefit of the production tax credits.

The projects are pending before the Commission in two cases.

One is the $1.13 billion wind repowering project and the other is the $2 billion project that calls for construction of the four wind facilities and the construction of or improvements to several transmission facilities in eastern Wyoming.

A tentative settlement agreement has been reached in the wind repowering case. The company's proposal calls for repowering, or upgrading, eight wind projects in Wyoming, four in Washington state and one in Oregon.

The facilities now represent 999.1 megawatts (MW) of installed capacity, and the project is expected to increase generation between 11 and 35 percent. Upgrades would include installation of higher-

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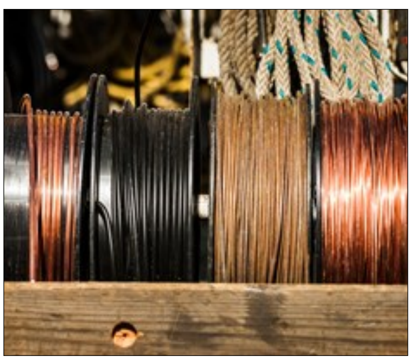
capacity generators and rotors with longer blades, which produce more energy at lower wind speeds.

In addition to increased energy output, the project's benefits would include greater control of power quality and voltage, which would allow the utility to more efficiently integrate wind energy into its transmission system and enhance the reliability of the electric grid, Rocky Mountain Power said.

The company also noted that the project's benefits can be achieved without the costs and complexity of permitting and constructing new facilities, while extending the facilities' useful life and cutting operating costs.

Rocky Mountain Power asked the Commission to issue its decision on the proposal by Dec. 29 in order to receive the full benefit of the production tax credits.

The current tax credit is $24 per megawatt-hour. That amount is adjusted annually but expires 10 years after a facility goes into service.



The tax credits for most of the facilities proposed for repowering are set to expire in 2018 and 2019. Overall, the company said, the repowering projects would lead to customer savings of between $41 million to $589 million, with natural gas prices and federal regulations representing the biggest variables.

The economic benefits are derived by a number of factors, including increased energy output, reduced operating costs, extended operational life, requalification for the production tax credits and the sale of renewable-energy credits.

Capital expenses related to the project would be assessed on customer rates through the Energy Cost Adjustment Mechanism, which can be adjusted up or down annually depending on costs incurred, and benefits reaped, by the company.

Rocky Mountain's $2 billion proposal requests Commission approval for CPCNs for four Wyoming wind projects with a combined capacity of 860 MW. Three have a capacity of 250 MW and one is capable of generating 110 MW.

The proposal also includes the construction of or improvements to several transmission facilities in eastern Wyoming. Most of the improvements are associated with the company's Energy Gateway West transmission project, which calls for the addition of approximately 2,000 miles of transmission lines in order to alleviate congestion on the transmission system, address growth and incorporate new generation sources such as wind.

The projects are mutually dependent, according to the company: The wind projects are not economic without the transmission projects, and the transmission projects are not economic without the wind resources.

The $2 billion cost estimate would lead to a rate increase of less than 1.9 percent in 2021, which is

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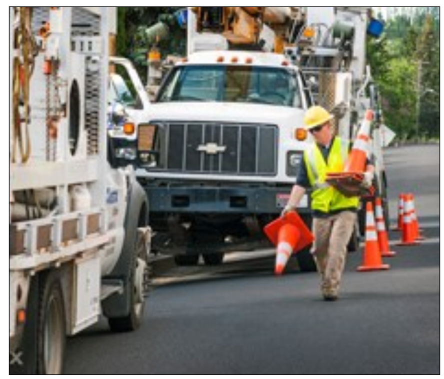
expected to be the first full year of operation of the new facilities, according to the company.

However, Rocky Mountain Power said the work is expected to save $137 million in avoided costs through 2050, when the wind projects are fully depreciated.

RMP proposal would lower wind integration rate, set solar rate

In August, Rocky Mountain Power requested approval to significantly lower the rate it charges to integrate wind energy into its system.

The company's proposal calls for lowering the integration rate from $3.06 per megawatt-hour (MWh) to 57 cents per MWh, and setting the rate for the purchase of solar energy at 60 cents per MWh.



The rates would apply to facilities that qualify for 20-year contracts under the Public Utility Regulatory Policies Act (PURPA). The law requires regulated utilities to purchase energy from qualifying independent power producers at rates established by state commissions.

In Idaho, facilities smaller than 100 kilowatts that are powered by intermittent sources such as wind and solar are eligible for 20-year contracts at the published rate set by the Idaho Public Utilities Commission.

The rate is referred to as the avoided-cost rate because it is intended that it not be higher than the rate at which the utility could generate the power on its own, or the rate at which the utility could purchase the energy elsewhere.

The integration rate for solar and wind facilities that qualify for power purchase agreements under PURPA is deducted from the avoided-cost rate paid by the utility.

In its proposal, Rocky Mountain said its analysis had found that the costs of wind energy and its integration had fallen significantly since the current integration rate was set in 2008.

Commission approves decrease to surcharge to reflect lower costs

In May the Commission approved a decrease to the Energy Cost Adjustment Mechanism to reflect a drop in power supply costs.

The ECAM allows the utility to adjust its rates each spring to account for expenses tied to the previous year's power purchases and sales. It appears on customer bills as a separate line item that increases if those costs are higher than the revenue generated through base rates. The ECAM surcharge decreases if the power supply costs are lower than the revenue generated through base rates.

Rocky Mountain said its power supply costs in 2016 were approximately $7.53 million lower than projected, primarily due to a decline in natural gas prices.

The change to the ECAM took effect June 1 and led to a decrease of 0.8 percent for residential customers, or about 73 cents per month for a typical residential customer who uses 800 kilowatt-hours of electricity. It is now assessed at .4958 cents for each kilowatt-hour used.

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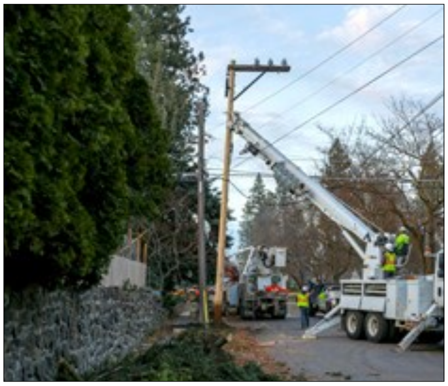
In the fall the Commission approved a change to a federal rate credit that led to a slight decrease in the power bills of Rocky Mountain customers.

The change to the Residential and Small Farm Energy Credit took effect Oct. 1 and lowered the bill of the average residential customer by $6.60 – or 51 cents more than the current credit, which expired Sept. 30.



The credit is the result of an agreement between the company and the Bonneville Power Administration (BPA) that passes through to customers the benefits of the federal Columbia River hydropower system.

BPA markets and distributes the wholesale power generated through the system, which consists of 31 federal hydroelectric projects on the Columbia and Snake rivers.

While customers of publicly owned utilities (rural co-ops, for example) have preferential access to BPA power, the Northwest Power Act of 1980 requires that customers of private, investor-owned utilities also share in the benefits of the federal hydro projects through a rate credit as part of BPA's Residential Exchange Program.