Electrical Power in Idaho

Idaho residents consistently enjoy some of the least expensive electric service in the nation. According to data compiled by the Energy Information Administration, Idaho ranked 49th of the 50 states and District of Columbia in electricity rates during 2010. (See next page for state-by-state ranking.)

Idaho Power Company

2012 Average Number of Customers/Avg. Revenue/kwh
(Computed from data available in FERC Form 1 Annual Reports)
400,291 Residential Customers/$0.0855
77,437 Commercial Customers/$0.0634
112 Industrial Customers/$0.0457

Avista Utilities

2012 Average Number of Customers/Avg. Revenue/kwh
(Computed from data available in FERC Form 1 Annual Reports)
106,528 Residential Customers/$0.0883
16,727 Commercial Customers/$0.0850
468 Industrial Customers/$0.0533

2012 Average Number of Customers/Avg. Revenue/kwh
(Computed from data available in FERC Form 1 Annual Reports)

PacifiCorp/Rocky Mountain Power

57,891 Residential Customers/$0.1027
8,507 Commercial Customers/$0.0865
5,549 Industrial Customers/$0.0638

Average Revenue by State

The information below is provided by the Energy Information Administration and reflects average revenue by kilowatt-hour by state in September 2013. While Idaho ranks 49th of 51 in average revenue, its rate of increase from September 2012 to September 2013, ranks third at 15%, behind only Rhode Island (22%) and Louisiana (16%). The 5 states with the highest average revenue are Hawaii, 32.24 cents per kWh; New York, 16.42 cents; Alaska, 16.22 cents; California, 15.8 cents; and Connecticut, 15.71 cents. The 5 states with the lowest average revenue are Washington, 6.99 cents; Wyoming, 7.62 cents; **Idaho, 7.76 cents;** West Virginia, 7.81 cents; and Illinois, 7.88 cents.

State	Sept 2012 (cents per kWh)	Sept 13(cents per kWh)	Change
Alabama	9.49	9.6	1%
Alaska	15.46	16.22	5%
Arkansas	8.04	8.21	2%
Arizona	10.32	10.78	4%
California	15.77	15.8	0%
Colorado	9.8	10.26	5%
Connecticut	15.49	15.71	1%
D.C.	11.63	11.91	2%
Delaware	11.34	10.8	-5%
Florida	10.66	10.53	-1%
Georgia	9.71	10.01	3%
Hawaii	33.82	32.24	-5%
Iowa	8.03	8.58	7%
Idaho	**6.72**	**7.76**	**15%**
Illinois	8.48	7.88	-7%
Indiana	8.21	8.72	6%
Kansas	9.43	9.77	4%
Kentucky	7.49	7.89	5%
Louisiana	7.1	8.25	16%
Massachusetts	14.26	15.64	10%
Maryland	11.47	12.1	5%
Maine	11.68	11.46	-2%
Michigan	10.95	11.06	1%
Minnesota	9.37	9.84	5%
Missouri	8.73	9.28	6%
Mississippi	8.69	9.42	8%
Montana	8.34	8.66	4%
North Carolina	9.47	9.46	0%
North Dakota	8.32	8.81	6%

State	Sept 2012 (cents per kWh)	Sept 13(cents per kWh)	Change
Nebraska	9.02	9.48	5%
New Hampshire	14	13.94	0%
New Jersey	14.19	14.22	0%
New Mexico	9.19	9.39	2%
Nevada	9.69	9.91	2%
New York	16.34	16.42	0%
Ohio	9.32	9.25	-1%
Oklahoma	7.88	8.54	8%
Oregon	8.18	8.29	1%
Pennsylvania	9.76	9.85	1%
Rhode Island	12.86	15.63	22%
South Carolina	9.23	9.34	1%
South Dakota	8.9	9.3	4%
Tennessee	9.67	9.4	-3%
Texas	8.87	8.89	0%
Utah	8.34	8.73	5%
Virginia	9	9.27	3%
Vermont	13.69	14.41	5%
Washington	6.82	6.99	2%
Wisconsin	10.61	10.82	2%
West Virginia	8.2	7.81	-5%
Wyoming	7.25	7.62	5%

Recent History of Base Rate Electric Cases

IDAHO POWER

Year	Requested	Granted
2004	14.5%	6.3%
2005*	6.3%	6.3% *(not a base rate case, but Increase granted due to tax settlement and Bennett Mountain plant)*
2006	7.8%	3.2% *(net was **14% decrease** due to expiration of tax adjustment.)*
March 2008	10.35%	5.2%
June 2008	Though not a base rate case, rates increased an average 10.7% due to a one-year PCA surcharge and 1.37% added to base rates for Danskin plant.	
2009	10%	4% (tiered-rates implemented)
2010	**No base rate cases.** Rates decreased an average 5.2%, due primarily to a Power Cost Adjustment decrease.	
June 2011	Three surcharge adjustments result in average 3% reduction for customers.	
2012	10%	4.2% (but net increase was 3.44% due to reduction in energy efficiency rider.)
2013	No base rate cases. But the annual Power Cost Adjustment was an average 15.3% increase effective June 1, the fourth-highest PCA on record.	

AVISTA UTILITIES

Year	Requested	Granted
2004	11%	1.9%
2008	16.5%	11.9% (Also included 4% PCA increase)

Year	Requested	Granted
2009	12.8% base rate increase with 5% PCA reduction, for net 7.8%	5.7% (but with 4.2% PCA reduction, net increase was 1.5 percent)
2010	14%	9.25% (but spread over 3 years)
2011	3.7%	1.1% (but with decreases in PCA and other rate components, the net is a decrease of 2.4 percent)
2013	4.6%	1.9% (with stay-out provision for next rate adjustment no sooner than Jan. 1, 2015. On Oct. 1, 2013, Customers got a 1.3% decrease due to reduction in Energy Efficiency Rider.

ROCKY MOUNTAIN POWER (PacifiCorp)

2005	5.1%	5.1% (This increase only applied to irrigation and industrial customers, there was no increase to residential.)
2007	10.3%	6.4%
2009	4%	3.1%
2011	13.7%	6.8% (but net increase to customers was 5.5% because of 1.3% reduction to Energy Efficiency Rider)
2013	--	A settlement prior to a formal case filed increased rates by an average 0.77% effective Jan. 1, 2014, with stay-out provision to Jan. 1. 2016. Effective Oct. 1, 2013, customers received a 1.3% reduction due to increase in BPA credit.

Summary of major cases

Commission rejects most of Idaho Power's proposed changes to net metering tariff

Case generates hundreds of comments; packed hearings

Case No. IPC-E-12-27, Order No. 32846
July 3, 2013

The commission denied nearly all of an Idaho Power Company application to change how customers who generate their own power should be treated. The utility proposed that residential and small commercial customers who net meter by generating their own power be moved into new customer classes and be paid differently for the energy they generate.

Even though the commission denied most of Idaho Power's application, the commission said the company raises valid issues that are more appropriately addressed in a general rate case.

Idaho Power has about 386 net metering customers who offset their electrical use by connecting their own generating resources (such as solar panels or wind turbines) to the utility's transmission grid.

Capacity cap

Idaho Power proposed to double the current capacity limit on the amount of energy that can be generated from net metering customers from 2.9 MW to 5.8 MW. Current generation is nearing the 2.9 MW limit. The commission said a cap "may disrupt and have a chilling effect" on net metering. However, the commission directed the company to provide an annual appraisal of net metering status and its impact on the reliability of the company's system.

Pricing

Idaho Power proposed to increase the monthly service charge for residential net metering customers from $5 to $20.92 and for small-business net metering customers from $5 to $22.49. To more fully reflect the cost of service associated with net metering customers' use of Idaho Power's distribution system, the utility proposed to establish a basic load capacity charge of $1.48 per kW for residential net metering customers and $1.37 per kW for small-business customers. It also proposed to decrease the retail energy rates net metering customers pay. (For example, a residential net metering consumer would pay a non-summer rate of 4.85 cents per kWh compared to a standard residential customer's rate of 7.23 cents per kWh for the first 800 kWh of use.)

The pricing changes are needed, Idaho Power said, because net metering customers are credited at the full retail rate and are able to avoid paying distribution expense as well as other fixed costs, such as billing, that other retail customers pay. As a result, those costs are passed on to other customers.

Idaho Power said residential customers with net metering systems differ from other residential customers in that they produce power, can offset their use of power, use transmission and distribution facilities in a different manner and require backup services.

The commission agreed that net metering customers "have some characteristics that could justify moving them into a separate rate class," but is concerned that the company's proposal is inconsistent with state energy policy, will discourage net metering and encourage "rate-gaming" where large customers would install a small solar system to qualify for lower retail energy rates.

The commission also agreed that net metering customers "do escape a portion of the fixed costs and shift the cost burden to other customers in their class." However, the commission said "more work needs to be done to establish the correct customer charge for those who net meter" and that "dramatic changes such as those proposed in this case ... should not be examined in isolation but should be fully vetted in a general rate proceeding." Idaho Power countered that this case presented a better forum to focus on net metering issues than would a general rate case addressing many unrelated issues.

Excess net energy

For those net metering customers who generate more power than they consume, Idaho Power proposed to stop paying customers and instead provide them with a kilowatt-hour credit that can be applied to future billing periods. Those credits would expire after the December billing period, the company proposed, with the excess applied against the annual Power Cost Adjustment to benefit all customers.

The commission approved the proposal to compensate net metering customers with a kilowatt-hour credit instead of a financial credit or payment. "While we want to encourage net metering, we believe a financial credit or payment may incent potential net metering customers to overbuild their systems." The net metering tariff is designed for those customers who wish to offset a portion of their load, not to be wholesale power providers. There already is a tariff schedule for small-power producers desiring to sell energy to the company, the commission noted.

However, the commission denied the company's proposal to allow the credits to expire at the end of December. The commission said the credits should carry forward to offset future net metering customer bills for as long as the customer remains on the net metering service at the same generating site.

The commission approved the company's proposal to modify the procedures net metering customers use to interconnect to Idaho Power's distribution grid.

The case generated hundreds of comments to the PUC and large attendance at workshops and hearings. Many customers said the changes proposed by Idaho Power would make it difficult, if not impossible, for net metering customers to recoup their investment and that net metering customers are such a small part of the overall company's revenue base that any rate inequities are insignificant.

Idaho Power maintained that while the current inequities in the pricing system are not significant numerically, the current provisions are not sustainable and that delaying the changes until net metering service expands will only increase the inequities.

The commission said it appreciated the extent of public participation in the case. "The public input was especially thoughtful and thorough and, based on the record before us, we find that the public overwhelmingly opposes the company's application," the commission said.

"Moreover, we are concerned that the company did not seek out or consider customer input before proposing such dramatic changes to the net metering provisions," the commission said. "We applaud the company for bringing this case and these issues to our attention. But we advise the company that it would enhance consideration of future program-specific changes if it informed and obtained feedback from its customers and other stakeholders before proposing them."

Several parties intervened in the case including the City of Boise, Idaho Clean Energy Association, Idaho Conservation League, Pioneer Power LLC, Powerworks LLC and Snake River Alliance.

Idaho Power granted CPCN for Bridger coal plant upgrades, but preferred ratemaking denied

Case No. IPC-E-13-16, Order No. 32929
December 1, 2013

Idaho Power is getting a certificate to allow it to invest in emissions upgrades at a Wyoming coal plant, but the Idaho Public Utilities Commission declined a ratemaking treatment that would have guaranteed the utility recovery up to about $130 million of the investment.

The preferred ratemaking treatment might have made it more difficult for Idaho Power to pull back from the investment at two units of the Jim Bridger coal plant if even more federal or state emission controls make the upgrades no longer economical, the commission said.

It is not inconceivable that during the installation of the upgrades, "a tipping point could be reached making them uneconomic," the commission said. "It is in the best interest of the customers, the company and the company's shareholders for Idaho Power to be continuously analyzing the impact of changing environmental regulations on its upgrade project. As the project moves toward completion over the next several years, we direct Idaho Power to return to the commission if viable alternatives to the Bridger Units 3 and 4 become available."

The utility must file quarterly reports updating the commission on any changes to environmental policy or regulations until the upgrades are placed in service.

Environmental groups urged the commission to deny the certificate and, instead, require Idaho Power to find the approximate 350 megawatts of generation (about one-fifth of the company's total baseload capacity) from renewable resources and increased use of energy efficiency programs.

But the commission said Bridger opponents were not able to outline a viable alternative that could "reasonably and timely replace the value of energy and capacity that Bridger provides."

"The suggestion ... that renewable resources and energy efficiency could somehow replace Bridger's ability to reliably provide energy and capacity is simply not realistic in the near-term," the commission said. Indeed, baseload plants like Bridger and the Langley Gulch natural gas plant make wind and solar generation more reliable by balancing their intermittent generation, the commission said. The baseload plants are also "critical to the reliable operation of the high-voltage transmission system in that they provide voltage and frequency support."

The commission emphasized that the "public interest is paramount," in considering Idaho Power's application. Without the upgrades, which are being required to meet Clean Air Act regional haze rules, the coal units would be forced to cease operation by December 2016 and that is not in the public interest, the commission said. "Cost-effective replacement resources that are dispatchable and reliable year-round do not presently exist nor could they be brought on line before the required dates."

The commission acknowledged the public's concerns about unnecessarily extending the life of the coal plant. (More than 200 written comments were received and 30 people testified at a standing-room-only public hearing.) "The detrimental effects of long-term coal use on human health, the climate, wildlife, land and water are well-documented. However, Idaho Power's analysis presented and (commission) staff's investigation confirmed that investment in selective catalytic reduction controls is presently the least-cost, least-risk alternative to both reduce environmental effects and allow reliable electric service to continue."

While the commission granted the certificate, denial of binding ratemaking treatment means the commission will be able to review costs as the project progresses. "Because of the uncertain future of coal-fired generation, we find it unreasonable to prematurely commit ratepayer dollars to support Idaho Power's investment," the commission said. Approval of such treatment would provide the company with economic, social and political assurance it seeks, while leaving ratepayers to "bear the risk of environmental uncertainties," the commission said.

PacifiCorp, which operates as Rocky Mountain Power in eastern Idaho, is the majority owner of the Bridger plant and is moving forward with installing the controls, receiving a certificate in both Utah and Wyoming in May of this year. The Idaho portion of the estimated $130 million would be amortized over several years, increasing Idaho Power's annual revenue requirement by about $18.8 million.

Idaho Power said it considered other options, including replacing the Bridger output with natural gas-fired generation. The utility argued the Bridger plant has the lowest dispatch cost of Idaho Power's thermal generation fleet.

Several parties intervened in the case including the Industrial Customers of Idaho Power (ICIP), which did not oppose the certificate, but did oppose pre-approved ratemaking treatment. The Snake River Alliance and the Idaho Conservation League opposed both, maintaining that Idaho Power understated the cost of likely environmental compliance measures and didn't examine other alternatives. They said the risks associated with investing in coal generation have not been adequately characterized or compared to risks associated with other options.

March 27, 2013

National utility group expresses support for IPUC position in wind cases

State Supreme Court decision in Grouse Creek case expected in late 2013

The National Association of Regulatory Utility Commissioners (NARUC) criticized a decision by a federal agency to sue the Idaho Public Utilities Commission over a matter already being litigated in the state Supreme Court.

"We are deeply disappointed in the Federal Energy Regulatory Commission's action in this case. It is not at all clear why FERC would take this drastic and unprecedented step at this time, '' said NARUC President Philip Jones, also a commissioner in Washington state.

NARUC is responding to a decision by FERC to pursue a federal court case over the Idaho commission's denial of power purchase agreements between Idaho Power Company and the developers of the Grouse Creek and Murphy Flats wind projects.

The Grouse Creek case was argued in August before the Idaho Supreme Court and a decision was expected late in the year.

The Murphy Flats project owners did not seek relief from the Idaho Commission's order denying the sales agreements until 14 months later, well beyond the Idaho Commission's statutory 21-day window during which parties can file petitions for reconsideration and the 42-day period during which parties can appeal to the Idaho Supreme Court.

"Historically FERC has allowed the parties in such a dispute to resolve their differences either through settlement or litigation between the parties themselves," Jones said. "FERC's decisions here seem to ignore its own longstanding practice."

FERC alleges the Idaho PUC is not complying with the federal Public Utility Regulatory Policies Act (PURPA) that requires utilities to enter into sales agreements with small renewable power developers at rates determined by state commissions.

In November 2010, Idaho's three largest electric utilities filed a petition to the Idaho commission asking that the size of the projects that qualify for published rates be lowered and the price the commission sets be investigated. The utilities said they were buying power they did not need at prices that were too high for their customers.

Idaho Power has 104 active PURPA contracts generating 783 megawatts. Idaho Power's average total system load is about 1,800 MW, meaning about 43 percent is PURPA generation. Meanwhile, PURPA developers are requesting contracts for another 188 MW and another 212 MW are in dispute or litigation, according to Idaho Power. The utility's customers have paid $1.2 billion for PURPA projects under contract and the utility's obligations for future payments on existing contracts is another $2.4 billion, Idaho Power claims.

In December 2010, the Idaho PUC lowered the size cap under which projects could qualify for the commission's published rates, from 10 average megawatts to 100 kilowatts. The obligation under PURPA for utilities to buy from qualifying projects larger than 100 kW remains, but the projects must negotiate a rate with the utility under a formula approved by the commission. Much of the 576 MW of wind energy Idaho Power buys is from wind projects developed by large-scale developers who positioned several 10 MW projects a mile apart (the FERC minimum) to qualify for the commission's published rates.

In June 2011, the Idaho commission denied approval of several wind projects, including Murphy Flats and Grouse Creek. The commission expressed concern about customers being "forced to pay for resources at an inflated rate and, potentially, before the energy is actually needed by the utility to serve its customers."

In an earlier FERC order stating its intent to pursue legal action against the Idaho PUC in the Murphy Flats case, FERC Commissioner Tony Clark dissented, writing, "More broadly, while PURPA was designed as a foot in the door for emerging renewable resources and small generators, I sympathize with concerns that PURPA is increasingly being used as a cudgel that would force consumers to bear undue burdens. ... (FERC) has now put itself in an awkward position. It will invoke the power of the federal government to proactively champion a private interest that may contradict the best interests of the consumers of a state."

NARUC's Jones said the states and the federal government have been able to work out their disagreements without court action. "For the better part of the last ten years, FERC and the states have worked well on several issues ... Given the challenges the utility sector is facing, FERC and the states should be working as cooperatively as possible. We understand there will be times when we disagree, but it is not at all apparent what FERC intends to achieve by taking a single state to federal court, particularly when other options are available."

The proposed Grouse Creek agreements were two 10 aMW projects near Lynn, Utah. The cost of the contract was $230 million over 20 years. The three 10 aMW Murphy Flats projects in Owyhee County were for $299 million over 20 years.

Grouse Creek Wind case timeline

- ✓ On **November 5, 2010**, Idaho Power, Avista and Rocky Mountain Power asked the PUC to investigate issues related to small-power (primarily wind) projects that qualify for the commission's published rates. The utilities asked that the cap on the size of projects that qualify for the published rate be reduced from 10 average megawatts to 100 kilowatts. The utilities said a rapidly expanding number of wind projects were having a profound price impact on customers and transmission systems. The utilities claimed the small-power projects PURPA was originally intended to encourage are now developed by sophisticated large-scale wind farms that break down several projects in order to fall under the 10 aMW limit and qualify for the more attractive published (or avoided-cost) rate.

- ✓ On **December 3, 2010**, the commission denied the utilities' request to lower the size limits of projects that can qualify for the published rate pending further investigation. However, the commission did say that any decision it makes in regard to lowering the limit would become effective **December 14, 2010.**

- ✓ On **December 28, 2010**, Idaho Power Company and Grouse Creek executed sales agreements for two 10 average-megawatt projects near Lynn, Utah. The projects were to have been paid the Commission's published rate effective before December 14, 2010.

- ✓ On **February 7, 2011**, the Commission reduced the size of wind and solar projects that can qualify for published rates from 10 aMW to 100 kW. The commission said it is not its intent to push small wind and solar QFs out of the market. However, the Commission said federal rules regulating PURPA development insist that rates for purchases from QFs be "just and reasonable to ***ratepayers*** and in the public interest – not in the interest of the QFs."

- ✓ On **June 8, 2011**, the Idaho Commission determined to leave the eligibility cap under which wind and solar projects can qualify for commission published rates at 100 kilowatts. As a result, developers of 12 Idaho Power Company wind projects and five Rocky Mountain Power projects whose contracts were executed after the Dec. 14 deadline will not be eligible for published rates. However, the wind projects could still be developed under a rate negotiated between the project developers and the utilities. Ten Idaho Power wind projects submitted just before the deadline have already been approved by the commission. Continuing to allow wind projects larger than 100 kW to be paid the published rate does not benefit ratepayers, the commission said. "If we allow the current trend to continue, customers may be forced to pay for resources at an inflated rate and, potentially, before the energy is actually needed by the utility to serve its customers," the commission said. "This is clearly not in the public interest."

- ✓ On **July 27, 2011**, the Commission denied Petitions for Reconsideration from 14 wind projects, including the Grouse Creek projects.

- ✓ On **September 7, 2011**, Grouse Creek appealed to the Idaho Supreme Court.

- ✓ On **October 4, 2011**, the Federal Energy Regulatory Commission (FERC) issued a Declaratory Order in a similarly situated case (the Cedar Creek projects) that said the PUC's decision not to approve the Cedar Creek projects was inconsistent with PURPA, but FERC declined to pursue an enforcement action against the PUC. The Cedar Creek and Grouse Creek projects were remanded to the PUC for further discussion. On December 2011, the PUC approved a settlement of the Cedar Creek projects proposed by the parties.

- ✓ On **September 7, 2012**, on remand, the PUC affirmed its decision disapproving the Grouse Creek agreements. **By their very terms, the Agreements were not effective until December 28, 2010.** Grouse Creek changed the configuration of the projects numerous times and did not agree to standard contract terms and negotiations until December 9. On December 14, Idaho Power asked Grouse Creek to provide missing information necessary to complete the agreement. The projects failed to name the transmission entity (BPA or PacifiCorp) to transmit the energy and failed to provide a legal description of the projects' locations. Grouse Creek signed the agreements on Dec. 20. Idaho Power reviewed and signed on Dec. 28. The agreements were filed with the Commission on Dec. 29, 2010.

- ✓ On **Oct. 19, 2012**, the Grouse Creek projects amended their appeal to the Idaho Supreme Court to include the PUC's Sept. 7, 2012, Order on Remand and on **Feb. 1, 2013,** the record was lodged at the Idaho Supreme Court and the projects moved that the Court hear arguments during August 2013 and the court agreed.

- ✓ On **January 15, 2013,** during the process of the Grouse Creek appeal to the Idaho Supreme Court, the projects petitioned FERC to initiate an enforcement action against the Idaho PUC.

- ✓ On **Feb. 4, 2013**, the IPUC filed a motion to dismiss Grouse Creek's FERC petition, arguing that Orders on Remand are more appropriately tested at the state level. The Grouse Creek petition to FERC makes no mention of its pending appeal before the Idaho Supreme Court, the established briefing schedule or their intent to seek an expedited oral argument in August. A FERC enforcement action against the Idaho PUC would have to be brought in Boise, the same location as the Idaho Supreme Court. But there is no case remaining at the Idaho PUC that could be subject to a PURPA enforcement proceeding since the Idaho Supreme Court has already obtained jurisdiction where the appeal record has been lodged. The IPUC further argues that the main questions to be addressed are questions of state contract law, thus more appropriately addressed at the State Supreme Court level.

- ✓ On **March 15, 2013**, FERC issued a Notice of Intent that will initiate an enforcement action against the IPUC, stating that Idaho Commission's June 8, 2011, and September 7, 2012, orders are inconsistent with PURPA.

- ✓ On **March 22, 2013**, FERC filed a complaint in the United States Court for the District of Idaho asking the Court to enter an order finding that the Idaho Commission violated PURPA, enjoining the IPUC from imposing conditions on the sales agreements between Idaho Power Company and the developers of the Grouse Creek and Murphy Flats wind projects, and directing the IPUC to issue orders approving the power purchase agreements.

- ✓ On **August 28, 2013**, the case was argued before the Idaho Supreme Court and a decision is expected by the end of the year.

Murphy Flats wind case timeline

On Nov. 20, 2012, the Federal Energy Regulatory Commission (FERC) announced it would initiate an "enforcement action" in federal district court against the Idaho Public Utilities Commission for the PUC's denial of power purchase agreements between Idaho Power Company and the developer of three wind projects near Murphy. It is the IPUC's view that this action by FERC is an unprecedented challenge to longstanding PUC legal process and could impose unreasonable cost on Idaho Power ratepayers.

- ✓ On **November 5, 2010**, Idaho Power, Avista and Rocky Mountain Power asked the PUC to investigate issues related to small-power (primarily wind) projects that qualify for the commission's published rates. The utilities asked that the cap on the size of projects that qualify for the published rate be reduced from 10 average megawatts to 100 kilowatts. The utilities said a rapidly expanding number of wind projects were having a profound price impact on customers and transmission systems. The utilities claimed the small-power projects PURPA was originally intended to encourage are now developed by sophisticated large-scale wind farms that break down several projects in order to fall under the 10 aMW limit and qualify for the more attractive published (or avoided-cost) rate.

- ✓ On **December 3, 2010**, the commission denied the utilities' request to lower the size limits of projects that can qualify for the published rate pending further investigation. However, the commission did say that any decision it makes in regard to lowering the limit would become effective **<u>December 14, 2010.</u>**

- ✓ On **February 7, 2011**, the Commission reduced the size of wind and solar projects that can qualify for published rates from 10 aMW to 100 kW. The commission said it is not its intent to push small wind and solar QFs out of the market. However, the Commission said federal rules regulating PURPA development insist that rates for purchases from QFs be "just and reasonable to ***ratepayers*** and in the public interest – not in the interest of the QFs."

- ✓ **On June 8, 2011**, the PUC disapproved three purchase power agreements between Idaho Power and the former developer of the Murphy Flats projects. The Murphy projects did not petition the PUC for reconsideration within 21 days, nor did it appeal to the Idaho Supreme Court within 42 days, as provided in Idaho law. Consequently, the PUC order became final and no longer subject to appeal.

- ✓ On **Aug. 16, 2012,** nearly 15 months after the IPUC denied the Murphy Flat projects, the new developer of the projects, First Wind, which acquired the assets of the projects in June 2012, petitioned the PUC to modify its order due to previously issued FERC orders filed by two developers of seven other wind projects. First Wind claimed the FERC orders related to the other projects "constitute new facts or information justifying modification of the (Idaho) commission's order."

- ✓ On **Oct. 12, 2012**, the IPUC declined to modify its original order because First Wind failed to timely seek reconsideration or appeal the PUC's order. First Wind's petition, filed nearly 15 months after the reconsideration deadline, represents an attempt by new owners to resurrect a long-dead claim.

- ✓ On **Nov. 20, 2012**, the Federal Energy Regulatory Commission (FERC) announced it would initiate an "enforcement action" in federal district court against the Idaho Commission for the PUC's denial of power purchase agreements.

- ✓ On **March 22, 2013**, FERC filed a complaint in the United States Court for the District of Idaho asking the Court to enter an order finding that the Idaho Commission violated PURPA, enjoining the IPUC from imposing conditions on the sales agreements between Idaho Power Company and the developers of the Grouse Creek and Murphy Flats wind projects, and directing the IPUC to issue orders approving the power purchase agreements.

Effect on Idaho Power ratepayers

The lack of a timely appeal disrupts the regulatory process, introduces uncertainty, and is contrary to the interests of ratepayers and utilities. In its order, FERC compares the Idaho Commission's action in First Wind with that of another wind project that timely appealed, but the two are not the same. In the case of the project that timely appealed, a settlement between all the parties was subsequently approved by the PUC and that project is going forward.

The Murphy projects, as is the case with many wind projects, were proposed under the provisions of the federal Public Utility Regulatory Policies Act (PURPA). Under PURPA, regulated utilities must buy from qualifying small-power producers at a rate published by state public utility commissions or negotiated between the utility and the project. One-hundred percent of the costs regulated utilities incur buying power from a PURPA project is passed on to ratepayers.

The total payment Idaho Power would have made to the developer and passed on to ratepayers over the three 20-year contracts is almost $300 million.

The PUC supports renewable development and, to date, has approved 139 renewable projects under PURPA, including 26 wind projects totaling 706 MW in just the last four years. However, the PUC's first priority is to meet its statutory obligation to provide adequate and reliable service at just and reasonable rates. In its June 8, 2011, order denying approval of several wind projects, including the Murphy projects, the PUC expressed concern about customers being "forced to pay for resources at an inflated rate and, potentially, before the energy is actually needed by the utility to serve its customers. This is clearly not in the public interest."

FERC Commissioner Tony Clark's dissent to the FERC order expresses that same concern: *"More broadly, while PURPA was designed as a foot in the door for emerging renewable resources and small generators, I sympathize with concerns that PURPA is increasingly being used as a cudgel that would force consumers to bear undue burdens. ... (FERC) has now put itself in an awkward position. It will invoke the power of the federal government to proactively champion a private interest that may contradict the best interests of the consumers of a state."*

PUC denies developer's motions in solar power case

Case No. IPC-E-11-15, Order No. 32913
October 29, 2013

The Idaho Public Utilities Commission ruled that the developer of a proposed solar project near Grand View failed to present persuasive evidence that it is entitled to ownership of all the Renewable Energy Credits or that it ever completed a legally enforceable obligation (LEO) that would have required Idaho Power Company to buy from the project. As of publication time for this report, the project developer had filed a Petition for Reconsideration with the Commission.

The federal Public Utility Regulatory Policies Act, or PURPA, requires utilities to buy energy from qualifying small renewable power projects at rates to be determined by state commissions.

The developer of the Grand View PV Solar Two project in Elmore County claims his project was ready to provide energy to Idaho Power, but the parties did not sign a sales agreement because they could not agree on who should receive the financial benefits of the Renewable Energy Credits (RECs) associated with the project. RECs are tradable environmental commodities, which represent proof that 1 megawatt-hour of electricity is generated from an eligible renewable energy resource. (In a separate case, the commission determined that revenue from REC sales be split 50-50 between the utility and the renewable energy provider for wind and solar projects that are 100 kilowatts or larger unless the

parties mutually agree to treat REC sales differently.)

Grand View maintains that the dispute as to who should keep the revenue from the RECs is separate from whether Idaho Power is obligated under PURPA to buy output from the solar plant. The commission denied Grand View's motion for a declaratory order, stating that the manager of the project admitted that RECs are an integral part of the project's financial viability and that without the revenue from the RECs, the project was not ready to sell energy to Idaho Power.

In an affidavit filed with the commission, Grand View manager Robert Paul said the project's business plan is based upon selling all the RECs associated with the project and that without the ability to sell the RECs, the "project's financial viability will be compromised." He also said the project's profitability and his ability to raise the capital necessary to build the project would also be compromised.

"We find these statements undermine Grand View's argument that it was willing and able to mutually obligate itself to supply power," the commission said.

The commission denied another request by Grand View Solar Two that the December 2012 commission decision to split RECs evenly between utilities and solar and wind projects not be applied to this case because the proposed sales agreement was offered in 2011.

However, the commission noted that REC ownership was the primary issue in an original complaint filed by Grand View Solar Two against Idaho Power. "It now suggests that we simply ignore the REC dispute – the very heart of Grand View's complaint, amended complaint and Motion for Summary Judgment," the commission said. "Grand View's argument to simply separate the REC dispute from the legally enforceable obligation issue is inconsistent with the facts and positions of the parties," the commission said.

Further, the commission said, both Grand View and Idaho Power were parties to the case that determined REC ownership and Grand View did not raise the issue or petition for judicial review at that time.

The commission has stated in prior orders that when a QF project and a utility are unable to agree to terms in their power purchase agreement, that commission has a responsibility to resolve the dispute. The commission noted that ownership of RECs is not an issue controlled by PURPA. "Although there is not Idaho statutory law specifically addressing the ownership of RECs in Idaho, the commission relied upon Idaho common law to determine the property interest associated with RECs. Our Supreme Court has declared that 'the commission has jurisdiction to examine common law contract issues between QFs and utilities.' "

Summary of major electric rate adjustments

Idaho Power has fourth largest PCA increase on record

Case No. IPC-E-13-10, Order No. 32821
May 31, 2013

Declining water, reduced revenue from surplus energy sales and ongoing wind power expenses all contributed to a $140 million Power Cost Adjustment, the fourth highest in PCA history. To make up for the shortfall caused by these factors, Idaho Power Company's residential customers will be assessed a one-year surcharge of an average 12.5 percent effective June 1. For all customers classes combined, the average increase is 15.3 percent.

None of the money collected in the surcharge can be used to increase Idaho Power earnings or salaries, but is kept in a deferred account, audited by the commission, to be used only for paying extraordinary power supply expense. While base rates cover fixed costs, the PCA, adjusted every June 1, covers costs that vary from year to year, and are largely outside the company's control. These costs are related largely to water levels, gas and fuel expense, transportation expense and renewable power contracts for projects mandated by federal law. In six of the last 11 years, the PCA has been a decrease or no change, but this year's is the fourth highest on record due largely to a 19 percent reduction in water the company uses to power its hydroelectric plants.

None of the parties to the case disputed the company's numbers in calculating the annual adjustment, but all parties, including commission staff, recommended spreading the increase over two or three years to soften its impact.

However, spreading the increase over two or three years could mean even higher increases for customers in 2014 and 2015 if the state experiences low water again and a new PCA surcharge is added to an existing surcharge.

"We are sympathetic to the request to spread the authorized rate increase over time, and we understand that allowing full recovery in one year will have an immediate, negative impact on all customers, some more than others," the commission said. "Our concern for creating the risk of compounding or 'pancaking' rate increases in the future overshadows the impact we know will be felt this year. Forecasts for water are, at best, uncertain. Given this, we find it too risky and potentially could compound rate shock for customers to spread this year's PCA recovery across multiple future years."

For an average residential customer who uses 1,050 kilowatt-hours per month the average monthly increase will be about $11.38.

These are the primary factors that contributed to the large increase in this year's Power Cost Adjustment:

- About half of Idaho Power's generation comes from its hydropower plants. Hydropower generation from April 1, 2012, through March 31, 2013 was 1.8 million megawatt-hours less than forecasted, a 19 percent reduction.
- Revenue from surplus sales has declined significantly. During those periods when Idaho Power is generating more electricity than its customers consume, the utility sells the surplus generation and shares 95 percent of the revenue with customers. Cheaper energy prices on the open market resulted in $48.7 million in sales, $61.4 million less than forecasted.
- About $62.6 million is attributable to power sales agreements between Idaho Power and renewable energy projects that qualify under the provisions of the Public Utility Regulatory Policies Act (PURPA). The federal act requires utilities to buy energy from qualifying renewable energy projects. About $60 million of that is from existing wind projects and another $2 million is from new wind added during the current PCA year.
- About $23 million is related to Hoku, the Pocatello polysilicon plant that failed last year. The company included the $23 million in base rates last year in anticipated revenue from Hoku that never materialized.
- The revenue sharing credited to customers since 2010 decreased to $7 million this year, compared to $27 million last year. If Idaho Power's return on equity exceeds 10.5 percent, half of the revenue above that amount is shared with customers through a reduction in the PCA.

The commission said a negotiated settlement in Idaho Power's last base rate case under which all parties agreed to keep PURPA and Hoku expense in the PCA rather than moving them into base rates causes a higher PCA at this time. If not for that decision, the commission said, the costs from the wind projects would have been included in base rates and customers would already be paying to recover them. The rate case settlement reduced the immediate base rate impact on customers, "but, as we see now, it has exposed them to a large increase in the PCA adjustment," the commission said. "Had this been a normal water year, the decision to recover those costs in the PCA would not have been so onerous. However, below normal water has compounded the rate impact." The commission said that until Idaho Power files a general rate case, the PURPA costs will accumulate and appear each year in the company's PCA.

The commission staff, Wal-Mart Stores, Inc., and the Snake River Alliance proposed to spread the increase over two years, while the Industrial Customers of Idaho Power (ICIP) and the Department of Energy argued for a three-year recovery. Large commercial and industrial customers will experience increases of 16.9 percent and 21 percent respectively. ICIP argued the longer recovery period was especially needed following the recent 7 percent increase related to the new Langley Gulch natural gas plant.

In its comments, the Snake River Alliance said, "At issue is whether the commission opts to impose on consumers the true cost of their electricity over the past year, punishing as that might be, or whether it defers some of the cost to 2014 without knowing if that bill may be even greater next year." SRA said it generally supports "recovering verifiable expenses as close to the time in which they are incurred," but is concerned that a one-year recovery will be "overly burdensome on the company's most vulnerable customers."

Idaho Power did propose a mitigation plan that would have recovered 9.6 percent in the first year and the remaining 5.7 percent in the second year. Commission staff proposed collecting about 7.8 percent each of two years.

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Idaho Power PCA Over the Last Decade

This year's PCA recovers $140 million. The two years that were higher followed the Westwide energy crisis. The 2001 PCA was $220.2 million and in 2002 it was $240.2 million. Here's a look at the PCA over the last 10 years.

2013 – 15.3 percent increase. $140 million.
2012 – 5.1 percent increase, ($43 million) but that is offset from a revenue sharing agreement for a net increase to customers of **1.7 percent**.
2011 – 4.8 percent **decrease**. $50.4 million.
2010 – 6.5 percent **decrease**. $41.9 million.
2009 – 10.2 percent increase. $194 million.
2008 – 10.7 percent increase. $106 million.
2007 – 14.5 percent increase. $30.7 million.
2006 – 19.4 percent **decrease**. $-46.8 million credit.
2005 – No change. $73.1 million.
2004 – No change. $70.8 million.
2003 – 18.9 percent **decrease.** $81.3 million.

Commission adopts settlement of Avista electric, gas cases

Case Nos. AVU-E-12-08 and AVU-G-12-07
March 27, 2013

The Idaho Public Utilities Commission adopted a settlement to the Avista Utilities rate case that considerably reduces the size of the increase originally proposed and delays an electric increase for another six months.

The settlement divides Avista's request into two phases with a 4.9 percent increase in natural gas rates on April 1 (Avista originally proposed 7.2 percent) and no electric increase.

On Oct. 1, customers received a net electric increase of 1.9 percent. (Avista originally proposed a 4.6 percent electric increase effective April 1.) Also on Oct. 1, customers received a 0.3 percent increase in natural gas rates.

The settlement precludes another base rate increase from becoming effective until Jan. 1, 2015, at the earliest.

Under the agreement, the bill of an average residential electric customer who uses 930 kilowatt-hours per month will increase by about $2 on Oct. 1. The gas increase for a residential customer who uses the company's average 60 therms per month will be about $2.82 per month on April 1 and another 31 cents per month on October 1.

"The settlement represents a significant reduction in Avista's requested revenue increase," the commission said. "Moreover, the stay-out provision prohibiting any new electric or natural gas base rate increase before January 1, 2015, provides an extended period of rate stability that might not otherwise occur," had the case not been settled and instead proceeded to a full hearing, the commission said.

Signatories to the settlement are Avista Utilities, commission staff, the Clearwater Paper Association, Idaho Forest Group and the Community Action Partnership Association of Idaho, (CAPAI), which represents customers on low and fixed incomes.

The electric increase, delayed until October 1, is a 3.1 percent increase to base rates. However, the settlement also provides that customers receive a $3.86 million credit due to an Avista settlement with the Bonneville Power Administration regarding BPA's use of Avista transmission lines over the last eight years. That credit reduces the net increase in electric rates to an average 1.9 percent.

The Oct. 1 gas adjustment is a 2.1 percent increase to base rates. However, that total is offset by a reduction in the annual Purchased Gas Cost Adjustment (PGA) resulting in a net 0.3 percent increase.

The additional annual revenue requirement allowed Avista is $7.8 million on the electric side and $3.1 million on the gas side. When Avista filed the case last October, it sought $11.4 million on the electric side and $4.6 million on the gas side.

The return on equity allowed is up to 9.8 percent. If the company earns above that, it must share 50 percent of the overage with customers. Avista is allowed to earn up to a 7.9 percent rate of return.

About 70 percent of its electric revenue increase and 48 percent of its natural gas revenue increase are attributed to the need to replace aging infrastructure and upgrade existing plant. Other expense increases are related to hydroelectric plant relicensing, mercury emissions compliance and federal reliability requirements.

About 21 commission staff members were assigned to the case. They submitted 199 formal production requests and numerous formal and informal audit requests. Staff also reviewed the more than 300 data requests and responses that were part of the latest Avista electric and natural gas rate case filings in Washington state. Three Idaho staff accountants conducted a week-long on-site audit of Avista's books and reviewed work papers of external auditors.

The commission, by state law, cannot accept or deny a requested increase without first considering the evidence. State law requires that regulated utilities be allowed to recover their prudently incurred expenses and earn a reasonable rate of return, which is also set by the commission. The burden of proof is on the utility to demonstrate if additional expenses already incurred were needed to serve customers and, if so, were they prudently incurred.

Avista serves about 123,000 electric and 75,000 natural gas customers in northern Idaho.

Commission adopts decrease in Avista PCA, but increase to Energy Efficiency Rider

Case Nos. AVU-E-13-04, Order No. 32892,
AVU-E-13-05, Order No. 32894
September 25, 2013

Avista electric customers will be paying about 0.4 percent more for electricity as a result of rate adjustments approved by the Idaho Public Utilities Commission. The increases in rates, effective Oct. 1, do not increase Avista earnings.

Avista's annual Power Cost Adjustment (PCA) adjusts electric rates up or down to account for conditions that change from year to year due to factors like weather conditions and fuel prices. When those conditions result in expenses that are less than anticipated, customers get a one-year credit. When those factors cause an increase in costs above that already included in base rates, customers get a one-year surcharge. This year, variable expenses were $3.8 million lower than anticipated, resulting in a 0.83 percent decrease for customers. The PCA portion of electric rates declines from 0.09 cents per kWh to 0.152 cents per kWh.

The commission also approved a 1.2 percent increase in Avista's Energy Efficiency Rider.

The rider, which increases from 0.146 cents per kWh to 0.245 cents for residential customers, funds about 30 programs that increase energy efficiency or shift electric demand from peak-use times when electricity is more expensive. The increase will allow the company to recover a $3.6 million shortfall in the rider account and allow continued funding of energy efficiency and demand response programs.

In approving the rider increase, the commission said that energy efficiency and demand response programs reduce the need for higher cost, supply-side resources such as a new or expanded power plant. The programs funded by the rider must pass cost efficiency tests that demonstrate that all customers benefit from the programs, not just those who directly participate in them. In other words, without the programs in place rates for all electric customers would be higher.

Most of the underfunded amount in the rider account is the result of Avista's efforts to incent customers to switch to higher efficiency fluorescent lighting fixtures. During 2012, the utility issued rebates to 4,740 customers who switched from the T12 fixtures to T8 fixtures. Avista had originally budgeted $1.2 million for the program, but customer participation was so high that the utility ended up paying $5.2 million in rebates.

Other programs include rebates for energy efficiency appliances, HVAC improvements and electric motor measures. Another program offers rebates to residential customers who convert from electric to natural gas for space and water heating.

During 2012, the programs resulted in Idaho electric savings of 24,183 megawatt-hours in addition to another 15,942 MWh in savings through Avista's participation in the regional Northwest Energy Efficiency Alliance, which is also funded by the rider.

Rates increase slightly under PacifiCorp settlement; but no further hike until 2016

Case No. PAC-E-13-04, Order No. 32910
October 25, 2013

The Commission approved a negotiated settlement that increased rates for customers of PacifiCorp (Rocky Mountain Power in eastern Idaho) by 0.77 percent effective Jan. 1, 2014. The agreement also provided for no further increases in base rates until Jan. 1, 2016, at the earliest.

For a residential customer who uses the company average of 830 kilowatt-hours per month, the increase is less than $1 per month, according to the company's calculations.

"The commission believes that the value of a small, less than 1 percent uniform increase for all rate classes over a two-year period and the company's agreement to not file another general rate case until May 31, 2015, provides significant value for customers," the commission said. "In particular, it ensures multi-year rate stability and is in the public interest."

A commission staff review of the company's application, which included an expansive audit of the Company's Results of Operations, revealed that the company was prepared to file a rate case with a requested revenue requirement of greater than $15 million. The settlement allows an additional revenue requirement of $2 million, which is the remaining expense for the Populus to Terminal transmission line already approved by the commission in a previous rate case.

The settlement further allows PacifiCorp to defer up to $5.43 million in expense associated with the new Lake Side II natural gas power plant south of Salt Lake City. The plant begins serving customers next summer and collection of costs related to the plant will be collected through the annual Energy Cost Adjustment Mechanism (ECAM) beginning in 2015 and then included in base rates after the next rate case. The ECAM, which can be an increase or decrease depending on other factors, is adjusted every April 1.

The settlement also:

- Allows PacifiCorp to defer any net increase or decrease in depreciation expense allocated to Idaho until after the next rate case. A settlement to that case is currently before the commission (Case No. PAC-E-13-02).
- Creates a regulatory asset for future recovery from customers of the expense allocated to Idaho for removal costs related to the retirement of the 172-megawatt Carbon coal plant near Helper, Utah.
- Accepts a new electric service agreement between PacifiCorp and its largest customer, the Monsanto phosphate plant near Soda Springs, which begins Jan. 1. 2014, with an initial term through Dec. 31, 2015. The agreement includes a new section that allows for an annual true-up of the credit Monsanto is allowed for agreeing to have its service interrupted to provide additional electrical load to PacifiCorp. There are still issues regarding the value of that interruption to PacifiCorp that the parties will continue to negotiate.

Increase to BPA credit means decrease for Rocky Mountain residential, commercial customers

Case No. PAC-E-13-11, Order No. 32901
October 2, 2013

A federal electric rate credit passed along to residential and small-business customers of Rocky Mountain Power increased Oct. 1, 2013 and the Idaho Public Utilities Commission is hoping a settlement of one remaining disputed issue will eventually result in a larger credit.

The commission adopted a Bonneville Power Administration residential exchange credit of 0.3095 cents per kWh on an interim basis pending further discussion. The credit was 0.1839 cents per kWh. For a residential customer who uses Rocky Mountain Power's average 840 kilowatt hours per month, the monthly credit increases from $1.54 to $2.60, resulting in a 1.3 percent decrease to the residential bill.

The Bonneville Power Administration markets and distributes power to consumer-owned electric utilities in Oregon, Washington, Montana and Idaho. BPA power is generated from federal dams in the Columbia River system. While customers of publicly-owned utilities (like rural co-ops and the City of Idaho Falls) have preferential access to BPA power, the Northwest Power Act of 1980 also requires that customers of private, investor-owned utilities (85 percent of Idahoans) also share in the benefits of the region's federal hydroelectric projects through a financial credit as part of BPA's Residential Exchange Program (REP). The amount of the credit is determined by formulas using various factors, including a utility's average system cost for producing power. If an investor-owned utility's average system cost to produce electricity results in rates higher than those offered to BPA public utility customers, customers of investor-owned utility are issued a credit.

PacifiCorp is one of six Northwest investor-owned utilities whose customers can qualify for a credit. PacifiCorp allocates its total credit among the three Northwest states it serves, including in eastern Idaho where it operates as Rocky Mountain Power. Commission staff disagrees with the way PacifiCorp has chosen to allocate its share of the credit to Idaho customers for the 2014-2015 fiscal years. The benefits to PacifiCorp customers in Oregon, Washington and Idaho total $69.5 million over two years, with Idaho scheduled to receive $6.55 million. The credit is partially determined by the amount of electric load served by PacifiCorp in each of the three states.

The commission agreed to adopt its staff recommendation that the 0.3095-cent per kWh be adopted on an interim basis, while reserving resolution of the disputed issue pending further discussions between staff and PacifiCorp.

Demand Response Issues

Commission allows Idaho Power to ramp down two demand response programs for one year

Case No. IPC-E-12-29, Order No. 32776
April 3, 2013

The commission allowed Idaho Power Company to considerably ramp down two of its demand response programs, a compromise from the company's initial application to suspend the programs for 2013. The ramped-down programs will give the commission and interested parties one year to review how the programs should be designed in the years ahead*. **(See following article on settlement approving the programs for beyond 2013.)***

The two programs impacted are only a portion of the 20 programs devoted to demand-side management.

The programs, one geared toward residential customers and the other toward irrigators, provide financial incentives to customers to not use power during those time periods when demand on Idaho Power's generation system is at a peak. Due primarily to the economic downturn, Idaho Power now claims its generating plants can meet peak demand in the summer months until at least through 2016, eliminating the need for the programs.

Under the "A/C Cool Credit" program, residential customers who signed up were credited $7 for each of three summer months to allow Idaho Power to remotely cycle air conditioners on and off during peak periods. Under the "Irrigation Peak Rewards" program, Idaho Power was able to turn off irrigation pumps through the use of an electric switch connected to customers' electrical panels.

Idaho Power claims it has enough generation to meet peak demand and that suspending the programs would save customers the approximate $5.5 million it spent during 2012 on the A/C Cool Credit program and $12.3 million on Irrigation Peak Rewards. The costs of the programs are passed on to customers through the annual Power Cost Adjustment (PCA) surcharge updated every June 1.

Instead of suspending the programs entirely, the commission adopted a negotiated settlement that provides a "continuity payment" of $1 per month to residential customers during three summer months who have been participating in the A/C Cool Credit program, even though air conditioner cycling will not occur. Participating irrigators will also receive continuity payments, but the payment amounts vary depending on which Peak Reward option irrigators chose. It is hoped those payments will incent customers from not dropping out while the programs are reviewed.

"We find that providing continuity payments as proposed for both residential and irrigation participants for 2013 adequately balances the need to maintain the two demand response programs while the commission and the parties evaluate the programs for 2014 and beyond," the commission said. "We also appreciate the thoughtful comments offered by customers about encouraging and maintaining participants," in the programs.

"We are disappointed that the company proposed to discontinue their use completely," the commission said, noting that reducing peak summer loads lessens Idaho Power's reliance on buying power or building new generation resources. "Valuable time and resources were used to develop effective ... programs, and we do not want to impair the effectiveness of these programs in the future when the company's peak loads surpass its supply resources." The commission agreed with one customer who said it may be cheaper for the company to cycle air conditioning units than to purchase or generate power from its own resources.

The commission said it also found merit in one customer's comment about using the programs to respond to unforeseen emergencies. "Although the company does not believe it will need to use these programs in 2013, we doubt that it has perfect foresight."

The commission will open a new docket to evaluate both programs for use in 2014 and beyond.

The "A/C Cool Credit" and "Irrigation Peak Rewards" programs were created in 2003 and 2004, respectively. During 2012, the two programs and another program targeted to commercial and industrial customers reduced demand on Idaho Power's system by 367 MW.

Settlement ensures ongoing Idaho Power demand response programs

Case No. IPC-E-13-14, Order No. 32923
November 13, 2013

The commission accepted a settlement that ensures continuity of Idaho Power "demand response" programs designed to reduce electric demand during summertime peak-use periods.

Earlier this year, Idaho Power Co. filed an application with the commission to temporarily suspend its "A/C Cool Credit" and "Irrigation Peak Rewards." The utility said the programs cost the utility and, hence, its customers more to operate than the value of the energy saved. The downturn in the economy reduced demand on Idaho Power's generation system, the company claimed, and its own forecasting did not show a peak-hour capacity deficit until 2016.

"A/C Cool Credit" paid residential customers $7 per month each of three summer months for allowing the utility to remotely cycle their air conditioning units. "Irrigation Peak Rewards," paid farmers to curtail irrigation during peak periods. A third program, "Flex Peak," offers incentives to large commercial and industrial customers to create customized efficiency programs.

The settlement, reached by Idaho Power, commission staff, the Idaho Irrigation Pumpers Association, Idaho Conservation League, Snake River Alliance and EnerNOC, Inc. , keeps costs lower by slightly reducing both the duration of the programs and the amount of credit paid customers who volunteer to participate. The settlement makes the demand reduction more valuable by eliminating, in most cases, the requirement on the utility to notify participating customers in advance of interruption.

The commission commended the parties who reached the settlement after five public workshops. The settlement allows the utility to leverage the investment it made when the programs started – enrolling customers, installing load-control devices, etc. – while operating them in a more cost-efficient manner, reducing costs to all customers.

Keeping the programs viable means they can be ramped up when needed, the commission said. "We believe it is important for the company to continue its demand response (DR) programs to ensure it has sufficient, reliable DR resources to meet expected deficits," the commission said. "Circumstances such as increased demand related to business relocation and expansion, coupled with increased residential construction can occur quickly ...." the commission said.

The parties agreed that the value to both the company and its customers of all the programs combined would be about $16.7 million annually. During 2012, Idaho Power spent $5.5 million on the A/C Cool Credit program and $12.3 million on Irrigation Peak Rewards. Much of that expense was in direct payments to customers. During 2012, these two programs and FlexPeak provided about 367 MW of peak reduction.

The settlement says demand response should be used not only during peak-use periods, but also to delay construction of new peaking capacity, avoid transmission line losses and provide improved reliability during emergencies.

Some of the program specifics include:

- **A/C Cool Credit** will be available on weekdays from June 15 to August 15. Participating customers will receive a $15 bill credit over three billing periods. Idaho Power will not actively market the program, but will recruit customers who move into a home where a load-control device has been installed because the previous owner agreed to participate. The company will accept new participants upon request.

- **Irrigation Peak Rewards** will be available also from June 15 to August 15 on Mondays through Saturdays from 1 p.m. to 9 p.m. Participants will receive a fixed incentive of about $16 per kW per season. If more than three interruptions occur, participants get a variable incentive. Participating irrigators will choose from one of three interruption options, two of which will not require advance notice of interruption. Interruptions can last up to four hours, but no more than 15 hours per week or 60 hours per irrigation season.

- **Flex Peak Management** would be available to commercial and industrial customers from June 15 to August 15 from 2 to 8 p.m. on weekdays. Participants get a fixed incentive for up to three interruptions and a variable incentive if more interruptions occur. Interruptions may last up to four hours, but no more than 60 hours per summer.

The Industrial Customers of Idaho Power participated in the discussions, but did not sign the settlement.

PUC denies utility request for funding mechanism

Annual price adjustment would have covered costs of demand response programs geared to large commercial, industrial customers

Case No. IPC-E-12-24, Order No. 32766
March 22, 2013

The Commission denied an Idaho Power Company request to immediately begin recovering from customers the expenses and carrying charges associated with an energy conservation program geared toward large commercial and industrial customers.

Idaho Power asked the commission to approve a yearly rate mechanism that would be adjusted every June 1 to pay for the program. The first adjustment under the new tariff schedule would have increased average residential rates by about 23 cents a month beginning June 1.

Under the program, eligible energy efficiency projects are customized to serve large customers at each of their sites to reduce electric use. Idaho Power pays financial incentives to these customers to implement efficiency measures such as motor rewinds and energy efficient refrigeration. The cost of the program is included in rates for all customers because all customers benefit from the reduced demand on Idaho Power's generation system. That reduced demand prevents the company from having to generate or buy energy from more expensive sources.

The large commercial and industrial program is Idaho Power's largest energy efficiency program, saving about 68 million kilowatt-hours in 2011, enough energy to serve the average needs of 5,400 residential customers for one year. The commission does not approve demand reduction programs like these unless cost-effectiveness tests show that all customers, not just those participating in the program, pay less for electricity than they would if the programs were not in place.

Idaho Power incurred about $8.1 million in expenses and carrying charges attributed to the program during 2011. The commission earlier determined the 2011 expenses were prudently incurred, but directed the company to defer the expenses in a regulatory account until it files its next rate case.

That deferral allows the company to accrue annual program expenses for recovery with profit later on. The commission had directed Idaho Power to address the issues of the amount of interest it ought to be allowed to accrue on the deferred balance and the amount of time over which customers would pay down the deferred account in its next general rate case. Rather than waiting for its next rate case, Idaho Power proposed the yearly mechanism to more timely recover the expenses. Under the current method of waiting until a rate case filing, there can be a lag of between 18 and 36 months before Idaho Power is allowed to recover expenses, the company claimed.

The commission disagreed, stating that a rate case provides a forum for all parties to address questions that would not be as thoroughly addressed in an annual rate recovery mechanism. "In fact, the comments filed by the parties demonstrate reasonable disagreements over issues necessarily reviewed when expenditures are placed in customers' rates," the commission said. These issues have direct bearing on the amount of recovery that can be included in rates, the commission said.

One of those issues is the amount of interest the company ought to be allowed on the deferred account. Both Idaho Power and the Idaho Conservation League (ICL) argued that allowing the company to earn the same rate of return on demand-side resources (acquiring energy from conservation programs that reduce demand) as it does on supply-side resources (acquiring energy from power plant production), would further incent conservation measures.

A second issue is about how much time should be allowed for customers to pay back the company's investment. The utility and the ICL also said a four-year amortization period should be allowed to reduce the company's risk because the incentives are not backed by physical assets and Idaho Power doesn't own or have control over the efficiency equipment owned by the large commercial and industrial customers.

Commission staff noted the custom efficiency program is a 12-year program and that a reduced amortization period to four years without a reduced interest rate would result in customers paying $12 million (after being grossed-up for taxes) for a program that included only $7 million in direct customer incentives.

Commission staff and the Industrial Customers of Idaho Power advocated that inclusion of these funds should be considered in a rate case. The Industrial

Customers also recommended the commission open a docket to investigate whether Idaho Power's demand-side resource programs should be managed by a third-party provider "that does not demand unnecessary and unwarranted returns in order to bring the correct 'business evaluation perspective' to the task of energy efficiency and conservation."

Two Rocky Mountain Power irrigation programs suspended; deemed not to be cost-effective

Case No. PAC-E-13-10, Order No. 32879
August 19, 2013

The Commission granted an application by Rocky Mountain Power to suspend two efficiency programs for irrigators that have been determined to not be cost-effective.

The programs, which were suspended effective July 15, 2013, include one in which participants turn in worn nozzles, gaskets or drains for equivalent new equipment at no cost and another where irrigators are given financial incentives when they make pivot and linear equipment improvements.

Rocky Mountain hired a third party, Navigant Consulting, which, the commission determined, "presented clear and compelling evidence," that the programs are not cost-effective. The programs are just part of a number of programs funded by a 2.1 percent "Customer Efficiency Services Rate Adjustment" on all Rocky Mountain Power customer bills. The Idaho commission requires that all programs funded by the 2.1 percent rider pass cost-effectiveness tests to ensure their cost does not exceed the savings realized for all the company's customers, not just irrigators who participate in the programs. The total program budget for 2012 was about $652,000.

During some years customer efficiency programs may be cost-effective but then other factors, such as decreased customer participation and market conditions, may render them not cost-effective, the commission said. "Therefore, the commission remains vigilant in its oversight and assessment of these programs and constantly seeks to ascertain whether program funds are being utilized in a cost-effective manner," the commission said.

Rocky Mountain will instead continue its "custom analysis" on a site-by-site basis that would include pre-installation measurements to develop savings estimates and then a post-installation verification of savings.

Integrated Resource Plans

Reduced load growth leads Avista Utilities to scrap or delay plans for natural gas plants

Case No. AVU-E-13-07, Order No. 32888
November 1, 2013

Avista Utilities, which serves about 125,000 electric customers in northern Idaho, claims that reduced load-growth projections will delay the need for a natural-gas fired plant by one year and eliminate the need for one of two natural gas plants that were projected for 2023.

The commission was taking comments on Avista's 20-year growth plan, called an Integrated Resources Plan at the filing of this report. The commission requires regulated electric and gas utilities to file plans every two years outlining how they anticipate meeting load-growth in the most cost-effective manner.

In 2011, the company projected annual load growth of about 1.6 percent, but the 2013 plan adjusts annual load growth downward to slightly more than 1 percent. Avista's plan says its own generation and its long-term contracts will provide enough energy to meet customer needs until 2020. The company may be short during peak winter periods in 2014-15 and 2015-16 but plans to meet those needs with market purchases. A long-term capacity deficit does not happen until 2020.

To address that deficit, the company's plan calls for the addition of an 83-MW simple-cycle combustion turbine natural gas plant in 2019. Beyond 2020, the plan calls for another 83-MW simple-cycle CT in 2023 and a 270-MW combined-cycle CT in 2026. Another simple-cycle natural gas plant of 50 MW is anticipated for 2032.

Energy efficiency programs decrease Avista's energy requirements by 125 average megawatts and that is expected to increase to 164 aMW by 2033. Absent energy efficiency programs, Avista would be resource-deficient earlier than 2020.

The 2013 plan removes a 35-aMW wind resource that was included in the 2011 plan. A 30-year power purchase agreement with the eastern Washington Palouse Wind Project in December 2012 (40 aMW) and changes in Washington state law eliminated the need for the 2019-20 wind addition.

For the first time since Avista's 2007 plan, costs related to greenhouse gas emissions have been removed. "Based on current legislative priorities and the President's Climate Action Plan, a national greenhouse gas cap-and-trade system or tax is no longer likely," the plan's executive summary states. Instead, the IRP forecasts some plant retirements to meet new environmental rules promulgated by state and federal agencies. Avista's thermal resources include five natural gas plants, a wood-waste biomass facility, and 111 MW from part ownership of two units of the Colstrip coal plant in eastern Montana.

Avista gets about half of its generation from hydroelectric plants, 33 percent from natural gas, 9 percent from coal, 5 percent from power purchases and 2 percent each from wind and biomass.

Completion of transmission plan key to long-range planning for Idaho Power Company

Case No. IPC-E-13-15, Order No. 32868
September 20, 2013

An Idaho Power Company long-range growth plan is counting on completion of a transmission line from Boardman, Oregon to Melba as its major new resource for power generation over the next 20 years.

Idaho Power's Integrated Resource Plan (IRP) projects the 500-kV line will bring in about 500 megawatts of additional power from Northwest energy markets into Idaho Power's southern Idaho territory.

Idaho's regulated electric utilities are required to file an IRP every two years with the Idaho Public Utilities Commission. The plan explains how the utility intends to provide adequate and reliable service to its growing customer base at the lowest cost possible over the next two decades. Idaho Power's IPR case was still open at the filing of the report.

The IRP is for planning purposes only and is updated to account for changing circumstances. Even if the Idaho Public Utilities Commission accepts the plan, the resource projects outlined must still be reviewed and evaluated for their need and prudency on a case-by-case basis. Idaho Power anticipates that its customer base will increase from the current 500,000 to about 670,000 by 2032 for an average load increase of 21 MW per year, or 1.1 percent annual growth.

Completion of the transmission line, expected in 2018, along with procuring another 150 MW through energy efficiency and demand reduction programs, was found to be the least cost of nine potential resource portfolios the utility considered, according to the company.

The transmission project has been in Idaho Power's IRP since 2006. The utility is still working on acquiring the necessary regulatory approvals and permitting. Idaho Power has a joint funding agreement for the transmission line with the Bonneville Power Administration and PacifiCorp, which includes eastern Idaho as part of its service territory.

The company hopes to have 150 MW of increased energy efficiency and demand reduction in place by 2017 and increasing that to 370 MW by 2032. A major upgrade of the Shoshone Falls hydroelectric plant, from its current 12.5 MW to 61.5 MW, is set to be completed by 2019.

The utility is also planning on upgrades at two out-of-state coal plants it co-owns with other utilities. Idaho Power currently has a case before the commission seeking authority to include about $130 million in customer rates for emissions control upgrades at the Jim Bridger plant near Rock Springs. A technical hearing in that case is scheduled for Nov. 22.
The plan also states that Idaho Power will “commit to” installing emission-control technology at its North Valmy plant near Winnemucca this year. The Bridger plant, of which Idaho Power owns one-third, provides 770 MW of capacity to Idaho Power customers and the Valmy plant another 283 MW. Idaho Power owns 50 percent of the Valmy plant.

Idaho Power also owns 17 hydroelectric projects, three natural gas-fired plants and one diesel-powered plant. About 45 percent of the utility’s generation comes from hydroelectric resources, 30 percent from coal, 14 percent from long-term power purchases, 7 percent from market-purchased power and 4 percent from natural gas and diesel projects. Of the long-term power purchase contracts, 63 percent of the generation comes from wind and 22 percent from hydroelectric resources. The company buys about 789 MW from 103 projects that qualify under the Public Utility Regulatory Policies Act, or PURPA. It also buys all the output from the 100- MW Elkhorn Valley wind project in northeast Oregon.

PacifiCorp plans to acquire most new generation from energy efficiency

Case No. PAC-E-13-05, Order No. 32890
September 17, 2013

The commission accepted the IRP from PacifiCorp, the electric utility that serves eastern Idaho but, at the same time, urged the utility to increase its efforts toward energy efficiency and demand reduction in the face of increasing coal costs.

Environmental groups claimed PacifiCorp, which does business as Rocky Mountain Power in eastern Idaho, Utah and Wyoming, did not take into account additional capital investment in coal plants they claim will be needed to meet federal environmental regulations.

Part of PacifiCorp’s long-range plan is to install emissions control equipment at three of its coal plants – Hunter Unit 1 near Castle Dale, Utah, and Jim Bridger Units 3 and 4 near Point of Rocks, Wyo. The utility also plans to convert the Naughton Unit 3 coal plant near Kemmerer, Wyo., to a natural gas-fired facility.

The Snake River Alliance and the Idaho Conservation League claim PacifiCorp ignored their repeated requests to include the costs of the coal plant retrofitting that may be needed to meet the draft regional haze rules. Including those costs would make alternatives, such as increased emphasis on energy efficiency and demand reduction more attractive, the groups claimed.

PacifiCorp projects it will meet 67 percent of its future generation needs through energy efficiency, acquiring 953 megawatts within the next decade.

Other projected resources include 140 MW of solar generation, 12 MW of combined heat and power and between 650 and 1333 MW of market power purchases.

The company anticipates more market purchases because wholesale power and natural gas prices are down significantly due to the expansion of shale gas exploration in North America.

Without these additions, the company anticipates a system capacity deficit of 824 MW starting this year, increasing to 2,308 MW in 2022.

The commission said it “offers no opinion” on the company’s preferred resource choices. However, the commission did say that while forecasting coal costs is “fraught with failure and uncertainty,” it seems likely that the Environmental Protection Agency will impose additional regulation on fossil-fueled generation such as coal and natural gas.

“In light of this contingency, it appears to be in the best interest of the company and its customers to continue to evaluate and devote more focus on the development of alternative energy resources.”

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

The commission directed the company to increase its efforts toward achieving higher levels of energy efficiency and demand reduction.

“Instituting cost-effective energy efficiency measures that reduce customer demand benefits everyone. Such measures can obviate the need for new generation resources and thereby decrease the constant upward pressure on energy pricing.” Efficiency programs “are almost always preferable” to building new natural gas plants or buying power from the market, the commission said.

In its six-state territory, PacifiCorp anticipates average load growth of 1.1 percent per year. In Idaho, however, expected annual growth is 0.57 percent.

The company does not anticipate significant load growth in its Utah, Idaho and Wyoming territory primarily because of load request cancellations in Utah and Wyoming caused by “prolonged recessionary impacts and permitting issues.”

The utility also plans to increase generation with expanded transmission that will allow it to dispatch resources more efficiently and improve reliability. Completion of the

Windstar to Populus transmission project, from Glen Rock Wyo., to Downey, Idaho, is slated to bring more wind generation.

In its comments, commission staff said there are indications that the need for the transmission line could be offset by accelerating efficiency and demand response programs and encouraged the company to consider the issue further. Because of slower than normal load growth, the company has deferred addition of a major generation resource until 2024 when it expects to add a 432-MW combined-cycle natural gas plant and 432 MW of wind generation.

The Idaho Conservation League claimed that PacifiCorp's "arbitrary and unexplained discounting of future carbon costs can expose customers to substantial risk." The Snake River Alliance questioned the need for the utility to upgrade and retrofit its coal plants and believes the company relies too heavily on uncertain market transactions in lieu of buying power from renewable resources.

PacifiCorp's largest customer, Soda Springs-based Monsanto, claims the company intentionally designed the IRP process to be overly complex so as to discourage participation.

PacifiCorp hosted 15 public input meetings before finalizing the plan.