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

2011 Average Number of Customers/Avg. Revenue/kwh

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

396,435 Residential Customers/$0.0788
77,038 Commercial Customers/$0.0586
117 Industrial Customers/$0.0450

Avista Utilities

2011 Average Number of Customers/Avg. Revenue/kwh

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

105,840 Residential Customers/$0.0900
16,633 Commercial Customers/$0.0865
476 Industrial Customers/$0.0550

2011 Average Number of Customers/Avg. Revenue/kwh

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

PacifiCorp/Rocky Mountain Power

57,187 Residential Customers/$0.0938
8,626 Commercial Customers/$0.0787
5,542 Industrial Customers/$0.0559

Average Rates by State

The information below is provided by the Energy Information Administration and reflects 2010 average retail electric prices. The U.S. average In 2010 was 9.83 cents per kWh. The 5 states with the highest average rates are Hawaii 25.12 cents per kWh; Connecticut, 17.39 cents; New York, 16.41 cents; New Hampshire, 14.84 cents; and Alaska, 14.76 cents. The 5 states with the lowest average rates are Wyoming, 6.2 cents; **Idaho, 6.54 cents;** Washington, 6.66 cents; Kentucky, 6.73 cents; and Utah, 6.94 cents.

Name	Average Retail Price (cents/kWh)	Net Summer Capacity (MW)	Net Generation (MWh)	Total Retail Sales (MWh)
Alabama	8.89	32,417	152,150,512	90,862,645
Alaska	14.76	2,067	6,759,576	6,247,038
Arizona	9.69	26,392	111,750,957	72,831,737
Arkansas	7.28	15,981	61,000,185	48,194,285
California	13.01	67,328	204,125,596	258,525,414
Colorado	9.15	13,777	50,720,792	52,917,786
Connecticut	17.39	8,284	33,349,623	30,391,766
Delaware	11.97	3,389	5,627,645	11,605,932
District of Columbia	13.35	790	199,858	11,876,995
Florida	10.58	59,147	229,095,935	231,209,614
Georgia	8.87	36,636	137,576,941	140,671,580
Hawaii	25.12	2,536	10,836,036	10,016,509
Idaho	6.54	3,990	12,024,564	22,797,668
Illinois	9.13	44,127	201,351,872	144,760,674
Indiana	7.67	27,638	125,180,739	105,994,376
Iowa	7.66	14,592	57,508,721	45,445,269
Kansas	8.35	12,543	47,923,762	40,420,675
Kentucky	6.73	20,453	98,217,658	93,569,426
Louisiana	7.80	26,744	102,884,940	85,079,692
Maine	12.84	4,430	17,018,660	11,531,568
Maryland	12.70	12,516	43,607,264	65,335,498
Massachusetts	14.26	13,697	42,804,824	57,123,422
Michigan	9.88	29,831	111,551,371	103,649,219
Minnesota	8.41	14,715	53,670,227	67,799,706
Mississippi	8.59	15,691	54,487,260	49,687,166
Missouri	7.78	21,739	92,312,989	86,085,117

Name	Average Retail Price (cents/kWh)	Net Summer Capacity (MW)	Net Generation (MWh)	Total Retail Sales (MWh)
Montana	7.88	5,866	29,791,181	13,423,138
Nebraska	7.52	7,857	36,630,006	29,849,460
Nevada	9.73	11,421	35,146,248	33,772,595
New Hampshire	14.84	4,180	22,195,912	10,890,074
New Jersey	14.68	18,424	65,682,494	79,179,427
New Mexico	8.40	8,130	36,251,542	22,428,344
New York	16.41	39,357	136,961,654	144,623,573
North Carolina	8.67	27,674	128,678,483	136,414,947
North Dakota	7.11	6,188	34,739,542	12,956,263
Ohio	9.14	33,071	143,598,337	154,145,418
Oklahoma	7.59	21,022	72,250,733	57,845,980
Oregon	7.56	14,261	55,126,999	46,025,945
Pennsylvania	10.31	45,575	229,752,306	148,963,968
Rhode Island	14.08	1,782	7,738,719	7,799,227
South Carolina	8.49	23,982	104,153,133	82,479,293
South Dakota	7.82	3,623	10,049,636	11,356,149
Tennessee	8.61	21,417	82,348,625	103,521,537
Texas	9.34	108,258	411,695,046	358,457,550
Utah	6.94	7,497	42,249,355	28,044,001
Vermont	13.24	1,128	6,619,990	5,594,833
Virginia	8.69	24,109	72,966,456	113,806,135
Washington	6.66	30,478	103,472,729	90,379,970
West Virginia	7.45	16,495	80,788,947	32,031,803
Wisconsin	9.78	17,836	64,314,067	68,752,417
Wyoming	6.20	7,986	48,119,254	17,113,458
U.S. Total	9.83	1,039,062	4,125,059,899	3,754,486,282

Revenue By Class/Average Monthly Residential Bills

Idaho Power Company Average Revenue in Cents Per kWh

	2011	2010	2009	2008	2007	2006	2005
Residential	7.88	8.08	7.78	6.71	5.92	5.94	6.33
Commercial	5.86	6.20	6.20	5.21	4.37	4.29	4.86
Industrial	4.50	4.47	4.52	3.65	2.91	2.95	3.43
Avg. Residential Bill/mo	81.96	81.59	84.29	73.15	64.55	64.32	66.88

Avista Utilities Average Revenue in Cents Per kWh

	2011	2010	2009	2008	2007	2006	2005
Residential	9.00	8.54	8.28	7.23	6.91	6.50	6.47
Commercial	8.65	8.36	8.02	7.05	6.69	6.56	6.53
Industrial	5.50	5.30	5.18	4.55	4.24	4.15	4.14
Avg. Residential Bill/mo	84.94	79.73	80.77	71.30	67.38	62.28	60.75

Rocky Mountain Power Average Revenue in Cents Per kWh

	2011	2010	2009	2008	2007	2006	2005
Residential	9.38	8.72	8.27	8.04	6.97	4.87	4.08
Commercial	7.87	7.19	7.00	6.74	6.53	6.32	6.01
Industrial	5.59	5.23	5.36	4.95	4.59	3.60	3.45
Avg. Residential Bill/mo	98.41	90.18	87.49	87.27	75.51	51.70	43.20

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.)

AVISTA UTILITIES

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

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)

These are base rate cases only and may not include yearly variable cost adjustments, such as the Power Cost Adjustment. The years shown reflect the year the rate increase became effective, not necessarily the same year the rate case was filed.

Summary of major electric rate cases

Case No. IPC-E-12-14, Order No. 32585
June 29, 2012

Langley Natural Gas Plant expense is allowed in rates

The commission is allowing Idaho Power Company to increase its annual revenue by $58 million to pay for a $400 million natural gas plant scheduled to be online July 1.

Average rates will increase by 6.8 percent to pay for the 330-megawatt Langley Gulch natural gas plant four miles south of New Plymouth. For an Idaho Power customer who uses 1,020 kilowatt-hours per month, the average monthly bill will increase by $5.63, from $82.72 per month to $88.35.

The commission determined in 2009 that the additional resource would be needed to meet customer demand and granted Idaho Power a Certificate of Public Convenience and Necessity (CPCN) to build the plant. "The company has a statutory obligation to provide electric service and, since 2004, has forecast a need for a baseload generation resource in 2012," the commission said when it granted the CPCN three years ago. The purpose of the 2012 case is to review the company's expenditures in building the plant.

While the total cost of the plant is $401.4 million, the order allows $389.4 million in base rates. About $7.2 million was included in rates during the company's 2011 general rate case and another $3.23 million will be incurred after June 30 and so must be included in a future rate case.

Commission staff performed a detailed review of the company's application and workpapers that included a comprehensive audit of the actual and estimated plant and transmission expenditures. The commission approved these adjustments:

- Removal of $300,000 that Idaho Power requested for a contingency fund to resolve potential issues after June 30;
- Removal of $251,894 in costs related to the bid process to construct the plant;
- Removal of $1.2 million in expense related to an upgrade in the Langley to Wagner transmission line from 183 kV to 230 kV and placing it in a Plant Held for Future Use account for possible recovery later. The commission said the $1.2 million should not be placed in rates now because the additional capacity "is not associated with the near-term operation of the Langley plant. This investment is associated with the future generation and transmission needs of the company."
- Removal of $75,000 in costs for splicing fiber optic cable that will not be incurred until after June 30.

Parties filing comments in the case included the Industrial Customers of Idaho Power (ICIP), the Idaho Irrigation Pumpers Association, the Snake River Alliance and commission staff, along with 11 customers.

Both ICIP and the irrigation association argued Idaho Power is experiencing declining load growth since the CPCN was granted in 2009. ICIP expressed concern that the low cost of operating the Langley plant would reduce use of the company's three coal-fired plants by 70 percent.

The irrigators said the commission should schedule a full rate case to review the gas plant's impact on Idaho Power's overall system given changing conditions. In the alternative, the irrigators said, the commission should grant no more than half the increase and require Idaho Power to file a general rate case. The Snake River Alliance argued that construction of the plant "was and continues to be ill-timed," and said Idaho Power has ample energy supplies, particularly so with the failure of both the Hoku polysilicon plant in Pocatello and the Micron-Transform Solar project in Nampa.

In its reply comments, Idaho Power acknowledged a decline in load of 1.5 percent, but said that without the Langley plant the company's peak-hour loads would still reflect a projected deficit of 28 megawatts next month, 169 MW in July 2013 and 224 MW in July 2014. The company maintained that ICIP did not take into account Idaho Power's use of its coal plants during below-average water years. Further, the company argued, the availability of Langley will significantly reduce the company's reliance on purchased power.

Regarding the temporary condition of declining load, the commission said it is "not afforded the use of hindsight to judge the reasonableness of issuing the CPCN to Langley three years ago. However, it is interesting to note that ICIP argued in the prior CPCN case that Langley would be an expensive plant to operate but now maintains Langley, 'will be Idaho Power's least expensive unit, on a variable cost basis.' "

The commission said granting half the increase, as requested by the irrigators, undermines the commission's 2009 order when it issued the CPCN and would violate the statutory binding ratemaking treatment included in that same order. The pre-approved amount included in that order was necessary to facilitate the financing of the Langley plant, the commission said.

The commission noted that it attempts to balance the interest of the utility and ratepayers and reduced the requested rate base commitment by $26 million to protect ratepayers.

June 1, 2012

Seven Idaho Power rate adjustments result in slight increase

State regulators adopted adjustments to Idaho Power Company rates in seven separate cases that overall represent about a 0.6 percent increase for all customer classes combined, but about a 0.3 percent decrease to the residential class.

The largest of these adjustments is a 5.1 percent increase to the annual Power Cost Adjustment (PCA), but that is offset by a revenue sharing agreement that reduces the PCA to about 1.7 percent.

On June 1 of every year since 1993, Idaho Power is allowed to adjust its rates up or down to reflect its annual cost of providing electricity. Because about half of the company's power generation comes from hydropower facilities, Idaho Power's power supply expenses vary from year to year due to changes in Snake River streamflows and in wholesale market power prices.

In 2010, the PCA was a 4.8 percent decrease and in 2011, it was a 6.5 percent decrease. However, this year Idaho Power's power supply expense is $70 million above what is now collected in the PCA. Idaho

Power's earnings are not impacted by the PCA. All the revenue collected in the PCA is kept in a deferred account, audited by the commission, and can be used only to pay down power supply expense.

This year's water forecast is slightly better than normal hydro conditions for the April-July runoff period, so water is not a primary factor. About 95 percent of the $70 million in additional power supply expense is in new power purchases from wind farms under the provisions of the federal Public Utility Regulatory Policies Act, or PURPA. PURPA requires regulated utilities to buy energy from qualifying renewable energy facilities.

The $70 million power supply expense is reduced by $27 million as the result of revenue sharing agreements adopted in the last two Idaho Power rate cases.

As part of the 2010 rate case settlement, Idaho Power was allowed to accelerate tax benefits to bolster its earnings if the company agreed to share 50-50 with customers all revenue exceeding 10 percent Return on Equity (ROE). If earnings exceeded 10.5 percent, 75 percent of that portion above 10.5 percent is shared with customers through a reduction in pension expense.

In a separate case filed at about the same time as the PCA, (IPC-E-12-13) Idaho Power reported an ROE higher than 10.5 percent. The customer portion of the sharing amount is $33 million. Grossed up for taxes, the amount applied against the PCA is $27.1 million and the amount applied against pension expense that would otherwise be included in customer rates is $20.3 million. The result for the PCA is about a 3.2 percent reduction.

Up until the agreement allowing Idaho Power to accelerate up to $45 million of investment tax credits, Idaho Power had not been able to earn its authorized rate of return for the previous decade. Improved earnings are important to maintain Idaho Power's ability to finance ongoing plant investments needed to serve customers. "The company's increased financial stability benefits customers by enabling the company to delay rate cases and potentially lower interest costs. It is beneficial to customers and to Idaho Power if the company can enhance its ability to stabilize earnings in the near term, strengthening the company's position in the financial markets and enabling it to reduce the cost of borrowing funds for operations or plant investment," the commission said in its order approving the agreement, which continues through 2014.

Following is a summary of the other rate adjustments effective today.

<u>Boardman balancing account, Case No. IPC-E-12-09, 0.18 percent increase</u>

In February, the commission approved Idaho Power's application to establish a balancing account related to the early closure of the Boardman coal plant in Oregon. Idaho Power is a 10 percent of the owner of the plant due to be closed in 2020.

The balancing account tracks, on a cumulative basis, the difference between revenues and expenses associated with the shutdown. It ensures customers pay only for actual expenditures. Idaho's share of the annual change to base rates the company is requesting to recover is $1.58 million. The proposed increase varies among customer classes with the proposed residential increase at 0.18 percent. The commission removed about $60,000 in contingency fees, reducing the company's overall request to $1.52 million.

The $1.52 million includes the return associated with Boardman capital investments net the accumulated depreciation forecasted through Boardman's remaining life, the costs of accelerating the plant's depreciation and the decommissioning costs associated with the shutdown.

Depreciation rates, Case No. IPC-E-12-08, 0.16 percent decrease

Originally, Idaho Power sought a $2.78 million increase to base rates to account for an increase in depreciation rates for plant-in-service. The increase was based on updated net salvage percentages and service life estimates for all plant assets, with the exception of the Boardman coal plant and automated meters, which are handled in separate applications. However, parties to the case, including commission staff and Micron Technology Inc. disagreed on depreciation expense for some components. The parties agreed to settle on a $1.38 million depreciation expense decrease rather than a $2.78 million depreciation expense increase.

Mechanical metering depreciation, Case No. IPC-E-12-07, 1.25 percent decrease

Idaho Power applied to decrease base rates by $10.55 million due to the removal of accelerated depreciation expense associated with removal of mechanical meters.

The company recently completed a three-year installation of automated meters. Mechanical metering equipment was fully depreciated on May 31. As a result, annual revenue decreased by $10.5 million, which reduces rates by 1.22 percent.

Fixed cost adjustment, Case No. IPC-E-12-12, 0.28 percent increase

The FCA, implemented in 2007, allows Idaho Power to recover the fixed costs it loses when conservation programs result in lower power sales.

Without a mechanism like the FCA, there is a financial disincentive for Idaho Power to promote energy efficiency and conservation because it loses revenue when conservation results in power sales declining. Sometimes referred to as "decoupling," the FCA decouples (separates) Idaho Power's fixed costs from its energy sales, assuring the utility will be able to recover its fixed costs as established in the most recent rate case regardless of how much energy customers save. If the company under collects its fixed costs of serving customers, customers get a surcharge. Conversely, if the company over collects fixed costs, customers receive a credit. The commission capped the percentage increase that could be collected from residential and small-business customers at no more than 3 percent.

This year, Idaho Power under-collected $8.83 million in fixed costs from the residential class and $1.48 million from the small-business class. The commission determined to blend the amounts to prevent the small commercial customers from receiving 1.02 cents per kWh surcharge and residential customers 0.18 cents per kWh. Assessing commercial customers that large an increase would have exceeded the 3 percent cap. Blending the two customer classes, the increase is 0.28 percent for both classes. This equates to a new FCA rate of 0.2028 cents per kWh for residential customers and 0.2597 cents per kWh for small-business customers.

Transmission deferral, IPC-E-12-06, 0.08 percent increase

Idaho Power is allowed to recover $2 million over three years for lost transmission revenue associated with a federal transmission case. The adjustment increases base energy rates by .0052 cents per kWh.

The Federal Energy Regulatory Commission (FERC) found that Idaho Power had assessed transmission fees to PacifiCorp for transmission service on Idaho Power lines that were significantly lower than the Open Access Transmission Tariff (OATT) rates Idaho Power proposed to charge other customers for similar transmission service. The rate charged PacifiCorp was part of three “Legacy Agreements” the two utilities entered into during the 1960s regarding transmission service from the Jim Bridger power plant in western Wyoming to each utilities’ respective service territories. Since the initial FERC order, Idaho Power petitioned for rehearing and did amend portions of the Legacy Agreements, but the utility lost on appeal.

Case No. PAC-E-11-12, Order No. 32432
January 10, 2012

Rocky Mountain Power rate increase phased in over two years

Electric rates for residential customers of Rocky Mountain Power will increase by an average 5.88 percent effective today and 5.4 percent in on Jan. 1, 2013, according to an order from the Idaho Public Utilities Commission. The overall average increase for all customers classes combined is 7.8 percent in 2012 and 7.2 percent in 2013.

Rocky Mountain Power serves about 72,400 customers in eastern Idaho.

The order is in response to a settlement proposed by commission staff, parties representing customer groups and Rocky Mountain in response to its request last May for an average 15 percent increase. The settlement is a 48 percent decrease from the company’s requested 2012 increase and prevents the company from filing another rate case to impact 2013 rates. The company’s own testimony indicated that, absent this settlement, it would have filed another general rate case later this year to recover what it estimates will be a dramatic increase in its power supply costs. Commission staff estimated that increase would have been for at least $30 million above the $34 million allowed in this case. The $34 million allowed is spread over two years, $17 million in each 2012 and 2013. As part of the settlement, the company agrees to not file another base rate case with rates to become effective before Jan. 1, 2014. (That agreement does not include annual adjustments such as the ECAM explained below.)

Commission staff stated said the settlement “represents a significantly better deal for customers,” than had the case progressed to a full hearing. The settlement represents an acceptance of every reduction proposed by staff plus an additional $700,000, according to commission utilities division director Randy Lobb.

The average bill for a residential customer who uses the company average of 837 kilowatt-hours per month will increase by $5.47 and $4.20 in summer and winter respectively in 2012 and by $5.36 and $4.10 per month in summer and winter respectively in 2013.

About $11 million of the $17 million added revenue for both years is attributable to the expense incurred by the utility to meet power supply demand from customers. Those increased costs are due to declining revenue from surplus electricity sales, the expiration of low-cost power purchase agreements and increasing coal costs. The remaining $6 million in non-power supply expense represent fixed costs such as operations and maintenance and investment in power plants and transmission. The $6 million allowed in fixed costs for each 2012 and 2013 is 62 percent less than that sought by the company.

Customers should be aware, however, that some of the company's power supply costs were not included in base rates and will be recovered through the company's annual Energy Cost Adjustment Mechanism (ECAM) in April 2013. "Cost recovery decisions in this case have a multi-year impact on customer rates," Lobb said. The commission allowed $1.045 billion in base rates for variable power supply costs, up from $1.02 billion. If the changing costs of power supply are in fact higher than $1.045 billion, the company recovers that through a one-year ECAM surcharge which is set every April 1. If costs of power supply are lower than that amount, customers get a credit. An ECAM surcharge can be used only to pay down power supply expense and cannot be used to increase company earnings.

The commission's order addressed two issues repeatedly addressed by customers during public workshops and hearings in Rocky Mountain Power's eastern Idaho territory.

Residential customers on the company's "Time of Use" rate were confused by a seemingly larger increase for them as compared to standard residential customers. The increase is 5.88 percent in the standard residential rate, but 7.96 percent for residential customers who sign up for Time of Use, which is a lower rate when customers shift a portion of their power consumption to off-peak hours such as late nights and weekends. Many time-of-use customers believed they were being punished because the percent of increase for that customer class is higher. However, the current average rate for Time of Use customers is 4.2 cents per kWh, compared to 9.6 cents per kWh for standard residential customers. The overall cents-per-kWh increase for Time of Use customers is .3 of a cent smaller than the increase for standard customers but appears larger because the percentage calculation is made from a smaller number. If customers compare the actual standard rate to the Time of Use rate "they will see the substantial value ... if they are able to shift their electrical consumption to off-peak hours," the commission said.

Despite that savings, only about 26 percent of Rocky Mountain residential customers (15,000 of 57,000) participate in the Time of Use program. "We can only surmise that this relatively low percentage of participation is at least partially attributable to the lack of information about the cost savings potential," the commission said. It ordered the company to provide a plan on how it can better educate its customers about the benefits of the program.

A second issue raised by customers is the perceived frequency of momentary outages. The commission directed the company to continue is service and performance quality reporting requirements adopted in a previous case, but with an enhanced emphasis on options for improvement.

Other issues addressed in the order included:

- The company agreed to abandon its pursuit of an increase the monthly customer service charge for residential customers. That charge will remain at current levels.
- The settlement approved the remaining 27 percent expense for the Populus to Terminal transmission line denied in the 2010 rate case until the line was fully utilized and benefitting customers. However, that expense will not be included in customer rates until on or after Jan. 1, 2014. Rocky Mountain agreed to drop its state Supreme Court appeal of the commission's prior ruling regarding recovery of the transmission expense.
- The commission denied a request by the Community Action Partnership Association of Idaho (CAPAI) to increase by 26 percent the money made available for a low-income weatherization assistance (LIWA) program. The commission said CAPAI has failed to provide an adequate accounting of previous allocations to the program. "While CAPAI is under no legal requirement to disclose to the commission a full accounting of its LIWA program distributions, the commission has a fiduciary duty to ensure that all of the allocations it directs the company to make to CAPAI are appropriately spent." The commission is opening a separate case to determine appropriate criteria for establishing funding levels for LIWA.
- Rate increase percentages for each major customer class in 2012 are 5.88 **residential**, 7.96 for **Time of Use residential**, 6.88 for **commercial,** 7 for **industrial,** 8.9 for **irrigation** and 8.9 for **large industry** and **special contract** customers.
- The cost to serve each customer class was brought 50 percent closer to actual cost, which represents "a step toward each class paying its fair share of the costs," while mitigating an even greater rate impact that would occur with a full cost of service move, the order said.
- The settlement allows large industrial customers Agrium and Monsanto to defer and amortize their ECAM balances through 2015 and establishes a new value that Monsanto will be paid for agreeing to curtail its consumption during peak use times.
- Parties signing the settlement include the Monsanto Company, the Idaho Irrigation Pumpers Association and the PacifiCorp Idaho Industrial Customers.
- The Community Action Partnership Association of Idaho (CAPAI) participated in settlement discussions but did not sign. CAPAI agrees with portions of the settlement but did not sign because the agreement does not include an increase for the Low Income Weatherization Assistance (LIWA). CAPAI also expressed concern over the frequency of Rocky Mountain Power rate increases, a perceived lack of transparency in the settlement negotiations and the impact on residential customers of simultaneous rate increase requests from Idaho Power Company, Avista Utilities and Boise-based United Water Idaho.
- Public workshops were held in Grace and Rexburg and public hearings in Downey and St. Anthony. Approximately 60 attended the Downey hearing with 12 testifying and about 115 attended the St. Anthony hearing with 26 testifying. The commission also conducted a telephonic hearing during which two testified. The commission received 75 written comments, nearly all opposed to any rate increase.
- The commission cannot, by state law, arbitrarily refuse to consider utility rate increase requests. State statutes require that all rate requests be considered by the commission to determine whether the expenses the utility seeks to recover through customer rates were needed to serve customers and if they were prudently incurred. When the commission denies expense recovery it must be able to legally demonstrate why the expenses were not needed or prudently incurred. All commission decisions can be appealed to the state Supreme Court by the utility, intervenors or customers.

Case No. PAC-E-12-03, Order No. 32507
April 2, 2012

Rocky Mountain annual ECAM is not an increase for most customers

For the first time since its inception three years ago, the annual Energy Cost Adjustment Mechanism (ECAM) will not result in an increase for most Rocky Mountain Power customers.

The ECAM covers power supply expenses not already included in base rates that cannot be predicted from year to year. For the third straight year, Rocky Mountain Power claimed it is not collecting enough to cover its power supply expenses but did not seek an increase from most customers because it believes power supply costs will decrease significantly next year. It recommended that the current ECAM rate be held constant to achieve rate stability over the next two years.

However, the utility, which serves 70,000 customers in eastern Idaho, did receive commission authority to collect $2.6 million in power supply expense from its two large-contract customers, Monsanto and Agrium. The total amount to be collected from Monsanto and Agrium for the ECAM account is $7.7 million, but collection of that amount is being spread over three years according to a settlement agreement in the company's 2011 rate case.

Most power supply expense is included in base rates, but because those costs vary from year to year due to changes in market rates, transportation expense and expiration of contracts with energy suppliers, the ECAM allows the company to make a one-year adjustment every April 1. The adjustment is a one-year increase to customers if power supply costs are higher than the amount already included in base rates and a one-year credit to customers if power supply costs are lower than the amount included in base rates.

In 2010, the ECAM was a 1.3 percent increase and in 2011, it was a 5.8 percent increase. The ECAM appears as a line item on customer bills under the company's tariff Schedule 94. Rocky Mountain Power's earnings are not impacted by the ECAM because all the money collected in Schedule 94 is kept in a deferred account that is audited by the commission and must go directly to pay power supply expense. It cannot be used for any other purpose.

Case No. PAC-E-12-11, Order No. 32606
August 3, 2012

Rider decrease means lower rates for Rocky Mountain customers

Rates for eastern Idaho customers of Rocky Mountain Power (PacifiCorp) declined about 1.3 percent Aug. 1 due to the commission's approval of the company's request to reduce its Energy Efficiency Rider.

The rider, which funds energy efficiency programs, decreases to 2.1 percent of customers' billed amounts, down from the previous 3.4 percent.

Fearing less of a commitment to energy efficiency, some Idaho conservation groups opposed the reduction.

Although its balance account for conservation programs was in a $1 million deficit on April 30, Rocky Mountain asserted that without a reduction it would have began over-collecting on the rider this month. The company is not proposing to modify or decrease its conservation program activities. The sluggish economy and cooler than normal weather in 2011 resulted in less participation in conservation programs, thus reducing expenses.

The rider, appearing as a separate line-item on customer bills, funds a number of programs that reduce consumption and demand on PacifiCorp's generation system, thus reducing costs for all customers. The commission performs cost-effectiveness tests on each of the programs to ensure that <u>all customers benefit, not just those who directly participate in the programs.</u>

The Idaho Conservation League and the Snake River Alliance said the rider should remain at 3.4 percent so that there will be funding available for an anticipated expansion of energy efficiency activity without burdening customers by "whipsawing" the rate up and down.

The commission expects Rocky Mountain to continue reviewing cost-effective programs, expand existing programs and create new ones as appropriate. But allowing what could be a significant accumulation of funds without knowing when or how much will be needed would be unfair to ratepayers, the commission said.

"Leaving the rider at its current 3.4 percent likely would create a large fund in search of expenditures, and that situation could undermine customers' confidence that their rates are prudently used to fund only cost-effective programs," the commission said.

Some of the programs funded by the rider include low-income weatherization, home energy efficiency incentives, refrigerator recycling, commercial and industrial efficiencies and an agricultural energy services program.

October 2, 2012
Case No. AVU-E-12-06

Avista's annual PCA is 2.17 percent reduction

Avista Utilities' northern Idaho customers received an approximate 2.17 percent decrease in electric rates effective Oct. 1.

The commission approved the utility's proposal to rebate customers about $3.1 million of over-collection in Avista's Power Cost Adjustment (PCA) account.

Customer rates are divided into two major components: variable rates (the PCA) and base rates. The variable rates are adjusted annually to account for expenses to utilities that change from year to year: wholesale electric, natural gas and transportation expense and water supply. When variable expenses come in higher than what is included in the fixed portion of customer rates (the base rate), customers are assessed a one-year surcharge. When variable costs are lower than what is included in base rates, customers are given a one-year credit. For Avista customers, the credit or surcharge expires every Sept. 30 and a new adjustment implemented on Oct. 1 depending on the previous year's actual conditions and a forecast of the next year's conditions.

For this PCA year, the adjustment is a credit of 0.09 cents per kWh, or an average decrease of 2.17 percent. Commission staff proposed delaying the $3.1 million credit to soften the impact of a potential base rate increase next spring. Avista notified the commission last August of its intent to file a general rate case in early October for new rates that would become effective next April or May. Waiting until after the base rate case, promotes rate stability, staff argued, by avoiding two rate adjustments in a short period. Idaho Forest Products filed comments objecting to the commission staff recommendation, asserting that customers should benefit now from the PCA credit.

The commission ruled that the credit should be applied immediately. The commission's staff promotion of rate stability is a "worthy goal," the commission said, but increases or decreases to rates every year "is an inherent attribute of the annual PCA mechanism. The year-to-year fluctuation of net power costs is the norm rather than the exception."

"Moreover, the commission finds that the PCA contains an implicit compact between the company and its customers to pass through the amount of excess power costs accrued during the deferral period," the commission said. "Based upon this record, we find no compelling reason to deviate from this arrangement."

Last week the commission approved an approximate 1.3 percent electric rate decrease due to a reduction in the rider customers pay to fund electric conservation programs.

Avista, headquartered in Spokane, serves about 125,000 electric customers and about 75,000 natural gas customers in northern Idaho.

September 27, 2012
Case No. AVU-E-12-07, Order No. 32652

Reduction in efficiency rider means lower rates for Avista customers

Electric rates will decline about 1.3 percent as a result of the commission's decision to adopt an Avista application to reduce the rider used to fund electricity conservation programs. Revenue from the electric rider now collected from customers at the current level will exceed the amount needed to fund the programs during the next year. Avista is reducing the amount collected in the rider by $3.46 million.

In its Washington and Idaho territories, Avista realized about 59,000 megawatt-hours of savings from energy efficiency programs, 115 percent of the company's goal. In its Idaho territory alone, the savings were 19,908 MWh during 2011. However, the end of the federal stimulus act that provided tax incentives for energy efficient measures and a sluggish economy that discourages customers from investing in energy efficient appliances has resulted in Avista needing only about 55 percent of projected revenue collected from customers in the rider.

The Snake River Alliance and the Idaho Conservation League opposed reducing the rider, stating the utility did not present enough evidence that it will over-collect the amount needed in rider funds and that the utility's projections should be made for two years, not just one year. Reducing the rider amount now may result in the company's failure to aggressively pursue energy efficiency programs in the future, they argued.

The commission said that allowing rider funds to accumulate "could undermine customers' confidence that their rates are prudently used to fund cost-effective programs. We find it would not be prudent for the company to retain rider funds for which it has no existing or projected use."

The commission said it still expects Avista to pursue all cost-effective efficiency programs and notify the commission if the new rider proves insufficient to fund the programs. The commission directed Avista to file a report within 60 days advising it about the opportunities the company believes exist for increasing customer awareness about energy efficiency issues and the company's current programs.

Case Nos. AVU-E-12-08 and AVU-G-12-07, Order No. 32671
November 2, 2012

Commission begins processing Avista rate case

Avista Utilities is seeking an average 4.6 percent increase in electric rates and a 7.3 percent to natural gas rates effective April 1, 2013.

If the increases were granted in full, the bill of an average residential electric customer who uses 930 kilowatt-hours per month would increase by $4.20 to $82.89. The gas increase for a residential customer who uses an average 60 therms per month would increase by about $4.12 per month to about $56.67.

The company seeks to increase its annual revenue by $11.4 million on the electric side and $4.6 million on the gas side. Avista is requesting an 8.46 percent rate of return and a 10.9 percent Return on Equity.

Parties intervening to date today include the Idaho Conservation League, Clearwater Paper and the Idaho Forest Group. Avista customers not representing customer groups will also be able to participate in the case by filing written comments and attending public workshops and testifying at formal hearings to be announced at a later date.

Avista claims the increases are necessary to expand and replace its aging utility infrastructure and meet its legal obligation to reliably serve customers. About 70 percent of the requested electric increase and 48 percent of the gas increase are due to increases in plant investment, while the remainder is due to increases in distribution, operations and maintenance and administrative expenses for both electric and gas operations. For example, the company replaces about 6,000 distribution poles each year.
Other expense increases are related to hydroelectric plant relicensing, mercury emissions compliance and federal reliability requirements.

Investment in facilities is growing at a faster pace than retail sales, according to testimony filed by Avista CEO Scott Morris.

Morris said Avista reduced its 2012 capital budget by $19 million to mitigate the impact of rate increases, but the company cannot reduce spending too much without jeopardizing reliability of service to customers.

"We have heard comments from some of our customers to the effect that Avista should cut its costs, and 'tighten its belt' like other businesses are doing in these difficult economic circumstances," Morris said. "But, at the same time, we are not like other businesses. Without the obligation to serve, we could consider refusing to hook up new customers, because it could avoid an increase in costs to our existing customers. Without an obligation to serve, we could consider no longer serving some of the more remote, most costly areas to provide service. Unregulated businesses have the opportunity to shut down aging facilities or under-producing retail outlets, eliminate product lines and cut back on investment and maintenance. We do not," he said.

Avista reduced its Defined Benefit Plan benefit formula by 28 percent for all new hires since Jan. 1, 2011. No long-term incentive compensation for executives is included in customer rates and only 42 percent of total executive salaries are included in rates, according to Morris' testimony.

Customers can read Morris' entire testimony at:
http://www.puc.idaho.gov/internet/cases/elec/AVU/AVUE1208/company/20121011MORRIS%20DI.PDF

Testimony from other company officials is also available on the commission's Web site. Testimony from other parties as well as commission staff will be added as the case progresses.

Two months ago, Avista electric customers received a 5.6 percent natural gas reduction and 3.4 percent electric rate decrease due to decreases in the variable components of electric rates.

Avista's last major rate case resulted in a net 2.4 percent decrease to electric customers on Oct. 1, 2011. There was a base rate increase of 1.1 percent to electric rates and 1.6 percent to gas rates. However, the electric rate adjustment ended up being a decrease because of a larger reduction in the annual Power Cost Adjustment.

Wind over the years

Dating as far back as 2005, Idaho's utilities, the Commission and renewable energy developers have been trying to determine the most equitable method to price and integrate renewable energy, particularly wind. Wind development, particularly under federal PURPA provisions, has been rapid, particularly in Idaho Power's service territory.

At the time this report was filed, the issue of avoided-cost and an appropriate surrogate avoided resource were still being debated with a final order from the Commission anticipated in mid-December 2012. The debate intensified during 2012 when some parties took their cases to the Federal Energy Regulatory Commission.

Here is a timeline of the issues as they have evolved.

June 2005 – Idaho Power Company files application to be granted a six- to nine-month suspension from its obligation under the federal Public Utility Regulatory Policies Act (PURPA) to buy energy generated by qualifying wind-powered projects.

PURPA requires regulated electric utilities to buy output from small-power producers. The amount the utility pays the developer, called an avoided-cost rate, is based on the cost the utility avoids by buying from the small-power producer and not generating the power itself or buying it from another source. All of the costs associated with PURPA power are passed on to customers.

Later, Idaho's two other major regulated utilities, Avista Utilities and PacifiCorp (then Utah Power) joined the case, seeking to be included in the moratorium. The utilities sought the moratorium to address the growing number of intermittent wind proposals, which, they claimed, could impact the reliability of the transmission grid. An Idaho Power analysis concluded that in order to safely integrate 1,000 MW of intermittent wind generation, it would be necessary to concurrently add 640 MW of combustion turbines to provide capacity when wind resources were not operating. Between November 2004 and its June 2005 filing, Idaho Power has signed contracts from wind developers totaling 61.5 MW and has applications pending before the commission for another 21.5 MW. The company has also received inquiries from developers intending to pursue another 193 MW of wind projects. Before 2004, Idaho Power had less than 1 MW of PURPA wind-powered generation under contract.

August 2005 – Rather than granting the suspension, the commission (Order No. 29839) reduced the size of non-firmed wind projects that can qualify for the commission's published rate from 10 megawatts to 100 kilowatts while the commission examined the case further. The commission said it needed more time to study the impact of intermittent wind projects on reliability for customers and to examine whether the higher price paid for PURPA wind projects is beneficial for customers who end up paying the cost of higher-priced energy. (The money Idaho Power pays wind developers is included as part of Idaho Power's overall power supply cost that is eventually passed on to customers in the company's power cost adjustment process every spring.)

February 2007 -- Idaho Power proposes that the 100-kilowatt limit on wind projects that can qualify for published rates be moved back up to 10,000 kilowatts or 10 megawatts. Idaho Power completed a wind integration study and asked the commission for a return to the 10 MW size cap if wind developers: 1) agree to share in the cost of state-of-the-art wind forecasting services; 2) include a guarantee in future wind contracts that demonstrates projects are mechanically capable to generate at full output during 85 percent of the hours during a month and 3) agree to accept a discount of $10.72 per MW for wind integration. Idaho Power would also agree to remove the "90/110 performance band" that stipulated when output was less than 90 percent of projections or more than 110 percent of projections, Idaho Power could pay developers a lesser market-based rate rather than the PURPA rate.

July 2007 – Avista Utilities and PacifiCorp also file cases proposing return to the 10 MW limit with conditions as proposed by Idaho Power.

August 2007 -- Commission staff conducted two workshops to explore whether the utilities and wind developers could agree to a generic wind integration adjustment, but the parties were unable to settle. With the parties unable to agree, the matter was put before the commission for a decision.

February 2008 – After nearly three years, three cases involving how much it costs to add wind resources to utilities' transmission grids are resolved. Three orders establish the amount of discounts utilities can assess against wind developers to account for the cost of integrating wind into their systems. The orders also removed the 100 kW cap on the size of small-power projects that can qualify for the published rate, bringing it back to 10 MW. Also removed was the 90-110 percent performance band that allowed utilities to pay wind developers a market rate rather than the typically higher state rate when wind output from projects fall outside the 90-110 range. The order established a tiered-discount for Idaho Power and Avista that increased as more wind is added, but caps the discount so that it can go no higher than $6.50 per MWh. For the first 300 megawatts of wind on a utility's system, the discount is 7 percent. That increases to 8 percent when a utility has contracts for 301 to 500 MW of wind and to 9 percent for 501 MW or more. The commission approved a flat discount rate of $5.10 for PacifiCorp, which operates as Rocky Mountain Power in southeastern Idaho.

November 2010 – After more than two years of relative calm, Idaho Power, Avista and PacifiCorp (now Rocky Mountain Power) file a joint petition asking the commission to investigate a number of issues related to small-power projects that qualify for published rates. The utilities asked that the eligibility cap on the size of projects that qualify for the posted rate be again reduced from 10 average megawatts to 100 kilowatts in 14 days. The utilities contend a rapidly expanding number of wind projects are having a profound price impact on customers and on transmission systems. The utilities claim that the small-power projects PURPA was originally intended to encourage are now developed by sophisticated large-scale wind farms that aggregate several projects to fall under the 10 MW limit within a mile apart from each other to qualify for the avoided-cost rate. When combined, these projects can total up to 100 or 150 MW interconnecting at a single delivery point. Idaho Power claimed it had 208 MW of wind generation and another 264 MW of approved wind contracts scheduled to be online by the end of 2010. Idaho Power said it could have 1,100 MW of wind generation on its system in the near term, which exceeds the amount of power used in Idaho Power's total system on the lightest energy-use days.

The commission denied the request to lower the size limits of projects than can qualify for the posted rate. However, the commission did say that any decision it makes in regard to lowering the limit would become effective Dec. 14, 2010.

February 2011: Commission issues order reducing the eligibility cap for wind and solar projects to qualify for published rates from 10 MW to 100 kW. The 10 MW limit remained for non-wind and non-solar renewable projects. The commission said the smaller size limit for wind and solar projects is temporary until a number of issues that led to a petition filed by the state's largest three electric utilities can be resolved. Wind and solar projects that signed agreements with utilities dated before Dec. 14 are still under the former 10 MW eligibility cap.

February and March 2011: With the commission's case still pending, the Idaho Legislature gets involved when residents in eastern Idaho, angry over wind development, form Idahoans for Responsible Wind Energy and lead the charge to declare a two-year moratorium on wind development. There is also significant opposition to the extension of a sales tax rebate on equipment used in producing renewable generation. The tax rebate was scheduled to sunset on June 30, 2011, unless extended by legislative action. The moratorium on wind development was killed in committee on an 11-8 vote.

The debate over whether to extend the sales tax rebate continued to the final day of the session. A compromise bill to extend the tax credit for just another four months failed on an 18-17 State Senate vote, the final vote of the legislative session. Consequently, the sales tax rebate expired.

Wind development was one of the major issues of the session, if not the major issue. Wrote John Miller of Associated Press: "*What to do about wind power in Idaho has become one of the most expensive issues in the Legislature this year, judging from more than a dozen lobbyists employed by the utilities, wind energy developers and foes of the industry ...*"

June 2011: The commission issues several orders that the contracts for 12 Idaho Power wind projects and five Rocky Mountain Power projects were executed after a Dec. 14, 2010, effective date for a lower eligibility cap – 100 kW – under which wind and solar projects could qualify for commission published rates. Thus, these projects were not eligible for the published rates. However, the 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 had already been approved by the commission.

Commission staff and other parties attempted to establish criteria that would allow the commission more discretion in determining whether a QF was truly a small project as anticipated by PURPA or a larger project that had disaggregated. The commission declined to adopt the criteria, maintaining that the potential would still remain for the criteria to be circumvented.

The commission said it will initiate another proceeding to investigate the methodology used to calculate the avoided-cost rate. "We believe it is more appropriate to first establish the just and reasonable avoided-cost rates before we implement procedures for obtaining the rate," the commission said. "While we recognize the impact that this decision will have on small wind and solar projects, it would be erroneous, and illegal pursuant to PURPA, for this commission to allow large projects to obtain a rate that is not an accurate reflection of the utility's avoided cost for the purchase of QF generation," the commission said.

The Northwest and Intermountain Power Producers Coalition argued that the 10 average MW cap has worked "remarkably well" for Idaho. "We fundamentally think that it is unfortunate that the three utilities initiated this docket at all," NIPPC said. "We believe that this docket has been an unnecessary exercise and that is because the system is not broken and, hence, it does not need to be fixed."

July 2011: Fourteen wind projects ask the Commission to reconsider its June orders. The Commission affirms the orders. Five Rocky Mountain Power projects and two Idaho Power projects appeal to the State Supreme Court.

August 2011: The five Rocky Mountain projects (Cedar Creek) file a petition to the Federal Energy Regulatory Commission, asking it to "institute an enforcement action" against the commission for violation of PURPA. Cedar Creek alleged that QFs are entitled to receive avoided cost rates on the date a legally enforceable obligation is incurred, not solely the date on which a contract is signed by both parties and fully executed. Cedar Creek alleged that legally enforceable obligation occurred well before the commission's Dec. 14, 2010, deadline.

October 2011: FERC issues an order declining to institute an enforcement action but said the PUC's June and July orders were "inconsistent with our regulations implementing PURPA." It said Cedar Creek may pursue its arguments in the appropriate court. The commission responds the same month by announcing it will schedule settlement discussions with Cedar Creek developers.

November 2011: The Commission issues an order announcing the scheduling for a new docket, GNR-E-11-03, to review the terms of PURPA power purchase agreements including, but not limited to, the surrogate avoided resource and Integrated Resource Planning methodologies for calculating avoided cost rates. After the several parties to the case pre-file direct testimony by Jan. 31, 2012, a settlement conference will be held Feb. 28. Rebuttal testimony will be filed by the end of June with hopes that the case will conclude by the end of July 2012.

December 2011: PacifiCorp (Rocky Mountain Power), commission staff and Cedar Creek reach a settlement. The Commission approves modified PURPA agreements and allows the projects to be moved from their original Bingham County location to a new site -- Ridgeline Energy's Meadow Creek wind farm in Bonneville County. The output from the three modified projects will be the same as was agreed to with all five original projects: an annual nameplate capacity not to exceed 133.4 megawatts with annual output not to exceed 50 average megawatts per month.

Because of already available transmission at the Meadow Creek site, the Cedar Creek projects are assigned to Ridgeline Energy. The scheduled operation date is moved up to Dec. 31, 2012, which qualifies the projects to receive Department of Treasury grants and other tax incentives before they expire.

December 2011: Commission staff meets informally with the developer of two Idaho Power wind projects, Grouse Creek Wind Parks, to see if that case could be settled. The Grouse Creek projects were the only two Idaho Power projects that appealed to the state Supreme Court. The commission sets oral argument for March 2012.

March 1, 2012: Two wind projects – Rainbow Ranch – in Idaho Power's territory file a petition for FERC to bring an action against the Idaho Commission. Rainbow alleges it is in a similar situation as Cedar

Creek. The Rainbow projects failed to appeal the PUC's June 2011 orders and, the commission argued, they were thus jurisdictionally barred from seeking relief in federal courts.

March 22, 2012: The Commission denies an Idaho Power Company motion to temporarily suspend the utility's federal PURPA obligation to enter into sales agreements with qualifying small-power producers. But, at the same time, the commission gave Idaho Power more latitude in determining a fair price for the energy it buys from the projects. Idaho Power said a suspension of PURPA development was needed while the commission processed the GNR-E-11-03 case. Idaho Power argued, it may be required under PURPA regulations to enter into contracts for energy it claims it does not need at prices it claims are too high, unduly inflating customer rates. The Commission said it could not suspend the utility's federal obligation to buy from qualifying facilities. But the commission said methods previously approved by the commission and used by Idaho Power to determine the rate paid developers "do not currently produce rates that reflect Idaho Power's avoided costs and are not just and reasonable, nor in the public interest." So the Commission, in Interlocutory Order No. 32498, directed that effective immediately and until the GNR case concludes, contracts for all Idaho Power projects more than 100 kW can be individually evaluated and the utility is not bound by some of the parameters that were used to calculate avoided-cost in previous contracts.

"As contracts are negotiated and presented to the commission for approval, parties should keep in mind that FERC regulations require that the avoided-cost rates for all QF purchases be just and reasonable to utility customers and in the public interest, and not discriminate against qualifying cogeneration and small-power production facilities," the commission said. "Further, utilities are required to purchase QF generation at a rate equal to the utility's avoided cost. The commission's case-by-case review will ensure QF purchase agreements satisfy these and other FERC requirements."

April 30, 2012: FERC declines Rainbow's petition to initiate an enforcement action against the Idaho Commission. However, FERC said the IPUC's June 2011 Order disapproving the Rainbow Ranch projects was "inconsistent with the requirements of PURPA and our regulations implementing PURPA."

Aug. 7-9, 2012: Technical hearings are conducted with the 27 parties who are part of the GNR-E-1-03 docket. The Commission identifies these as the major issues to be resolved in the case:

> **<u>Curtailment –</u>** Idaho Power proposes a new tariff Schedule 74 to establish a process that relieves utilities from mandatory purchase obligations during certain periods of light customer load. Idaho Power claims that federal regulations allow such curtailment to avoid cost increases to customers when the utility must back-down base load units to accommodate QF output and "then suffer an otherwise unnecessary increase in cost when it must use higher-cost power sources during the interval required to ramp base load units back up when higher load conditions resume." Renewable developers argue that PURPA allows for curtailment only to meet emergency operational needs, current avoided-cost rates are already adjusted for curtailment, and curtailment amounts to a retroactive modification of existing contracts
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> **<u>Renewable energy certificates –</u>** PURPA does not regulate and there is no Idaho state policy regarding who should reap the financial benefits of the RECs or "green tags" associated with QF projects. Commission staff maintains that if utilities are compelled by federal law to buy energy that is renewable, then the benefits of renewable energy should go with the energy purchased by the utility and its ratepayers. "It is illogical, unreasonable and unjust for ratepayers to pay for

what is, in reality, renewable energy through a must-purchase obligation under PURPA, not get the benefit of the renewable attribute that is produced with each kilowatt, and then be required to pay through rates again when the utility purchases RECs," in order to meet a state or federal renewable portfolio standard," commission staff states. Developers argue that RECs should remain with QF developers because they are not compensated for environmental attributes under PURPA provisions that compensate QFs only for energy and capacity. They argue that allowing utilities to own RECs would re-open past agreements and amount to a taking of private property.

New formula to determine avoided-cost – Idaho Power proposes to replace the current method to determine the avoided cost rate to what it calls an "hourly incremental cost" methodology based on the highest-cost displaceable resource (typically a company-owned thermal plant or a long-term purchase contract). The hourly cost is totaled each month to arrive at heavy-load and light-load pricing for each month of the contract term. The utility argues that this method more accurately reflects true avoided-cost. Renewable developers argue that Idaho Power is adopting a "short-run" avoided-cost model and arguing for shorter contract lengths to artificially deflate avoided-cost rates, contrary to federal law. They say the hourly method is too complex and needs hourly updating, which contributes the utilities' ability to "game" the system. Further, the formula does not take into account the value of market sales of QF power during times of surplus and wrongly excludes potential carbon costs.

Contract length – Most PURPA contracts are for 20 years. Idaho Power proposes 5 years.

Delay damages and delay security – Idaho Power argues these damages ($45/kw) should remain a part of QF purchase agreements when a project is more than 90 days beyond its scheduled operating date or defaults entirely. Developers argue they don't reflect actual damage to the utility and are punitive.

Aug. 31, 2012: The Commission adopted a settlement between Idaho Power and the developer of six proposed wind projects that allows the projects to be terminated in exchange for Idaho Power returning letters of credit valued at $3 million to the developer. Exergy Development Group of Idaho was under contract to deliver power from the six projects -- four approved in 2005 and two approved in 2011 – but none of the projects met their scheduled operation dates.

The commission said both Idaho and its ratepayers benefit from the settlement. "In particular, ratepayers avoid paying nearly $600 million in energy payments over the 20-year terms of the Purchase Power Agreements. From Exergy's perspective, it recovers the four Letters of Credit." Further, termination of the agreements permits Idaho Power to avoid buying a monthly average of 60 megawatts of electricity that the company claims is not necessary to meet its service obligations.

The two 2005 projects were Notch Butte Wind Park, located between Twin Falls and Shoshone, and Lava Beds Wind Park, between Blackfoot and Arco. The original online date for those projects was May 2007, but that was postponed to September 2010. The four 2011 projects – Cottonwood Wind Park, Deep Creek Wind Park, Rogerson Flats Wind Park and Salmon Creek Wind Park – were all proposed in the Rogerson area and were to have been operating by June 30, 2012.

Sept. 7, 2012: After unsuccessful settlement negotiations and oral argument, the PUC again declines to approve a sales agreement between Idaho Power and the Grouse Creek projects near Linn, Utah. Grouse Creek argued that because FERC issued a declaratory order that opened the way for similarly situated wind projects in eastern Idaho – *the Cedar Creek projects, see October 2011 above* – to eventually be approved, that the commission should also reverse its earlier denial of the Grouse Creek projects. However, the commission ruled the circumstances surrounding Cedar Creek and Grouse Creek are not the same. The commission noted that Grouse Creek, unlike Cedar Creek, was unable to negotiate a settlement agreeable to all parties and is relying on a FERC Declaratory Order that is not binding on the commission. "Furthermore, the language of FERC's Declaratory Order leads us to doubt whether FERC understood the basis upon which the (Idaho) Commission made its initial decision to disapprove the agreements," the Idaho Commission order stated. "The Idaho Commission has aggressively and proactively enforced PURPA, as evidenced by the abundance of QF projects that now operate in our state." The Grouse Creek case is now pending appeal before the Idaho Supreme Court.

Sept. 20, 2012: A majority of FERC grants a petition by Idaho Wind Partners for a Declaratory Order stating that Idaho Power's proposed Schedule 74 curtailment tariff *(see Aug. 7-9 entry)* violates PURPA. The Idaho Commission objected to the motion noting that FERC was acting even before the Commission had ruled on the matter, which is part of the GNR-E-11-03 docket. In his dissent, FERC Commissioner Tony Clark stated, "By this order, (FERC) is allowing one party in a state proceeding to cherry-pick a single issue in a larger, ongoing case. By putting its thumb on the scale prior to the state commission even finishing its work, we could inhibit the parties' willingness, or the Idaho Commission's ability, to come to a flexible, tailored accommodation that may meet the concerns of multiple parties – most important, Idaho consumers." Idaho Wind, noting that Idaho commission staff testified in favor of the curtailment schedule during the August technical hearings, argued the FERC order is necessary to "forestall an Idaho Commission order that would be inconsistent with PURPA."

Oct. 5, 2012: The commission denies a complaint by XRG, developer of four wind projects in Cassia County, against Rocky Mountain Power. XRG maintained its yet-to-be-constructed wind projects should have been eligible to be paid a higher rate by Rocky Mountain because it requested a proposed power purchase agreement with the utility in January 2009, well before the commission's March 2010 decrease to the published rate wind developers were allowed at the time.

Rocky Mountain Power alleged that transmission in the area XRG was requesting to interconnect was constrained and XRG did not have the interconnection and wheeling agreements with Raft River Electric Cooperative and the Bonneville Power Administration needed to deliver the proposed wind projects' output to Rocky Mountain's territory. XRG said securing firm transmission and interconnection rights before creating a legally enforceable power purchase agreement is not a requirement in Idaho. Rocky Mountain Power claimed that when power must be delivered from off its system through other entities, some of which are not regulated by the Idaho commission – such as Raft River Electric – advance agreements are necessary.

After oral arguments, the commission ruled that XRG failed to establish that allowing its interconnection agreement with BPA to lapse was due to bad conduct by Rocky Mountain Power. "XRG made a choice at that time allow its interconnection request with BPA to lapse because BPA was requiring $80,000 for an additional interconnection study," the commission said.

Further, XRG did not prove it took sufficient steps to ensure it could deliver energy to Rocky Mountain Power. Communications waned between XRG and Rocky Mountain Power during 2009 and early 2010, the commission said. “It was not until March 2010, when XRG received notice of the commission’s intent to revise its published avoided cost rates that XRG attempted in earnest to establish its entitlement to contracts.” XRG did not file its complaint requesting grandfathered rates to pre-March 2010 rates until July 29, four months after the rate change.

While the commission was reconsidering the XRG complaint, XRG amended its complaint, asking the commission to approve the post-March 2010 rate if it cannot find in favor of the earlier higher rate. The commission declined. “It is wholly inappropriate and patently unfair for XRG to request an amendment 12 months after its original complaint was filed and more than four months after a final order has been issued on its complaint,” the commission said.

Oct. 12, 2012: The Commission declines to modify its June 2011 order that denied power purchase agreements between three Murphy Flats wind projects and Idaho Power. The developer of the projects that were to have been built near Murphy argued that two declaratory orders issued by the FERC subsequent to the Idaho commission’s June 2011 order “constitute new facts or information justifying modification of the (Idaho) commission’s order.”

But because Murphy Flats did not timely appeal the Idaho commission order, the projects are prohibited by law to re-litigating an already decided issue, the commission said. Parties to commission orders may file petitions for reconsideration within 21 days after a commission order and then may appeal to the state Supreme Court. Murphy Flat’s request came more than 14 months after the reconsideration deadline and 10 months after the FERC order. “The commission’s ability to amend an order cannot be used to create a right of appeal or other remedy lost by a party’s lack of diligence,” the commission said.

Oct. 16, 2012: Thirteen of 25 parties propose a partial settlement dealing with the security deposits and damages issues in the generic wind docket, GNR-E-11-03. Settlement discussions were also held on Idaho Power’s proposed tariff to curtail wind generation during certain light-load conditions but the parties were not able to agree on that issue.

The proposed partial settlement requires renewable power projects to post a security deposit, or performance bond, within 30 days after the commission issues its final order approving a power purchase agreement. The parties propose that the deposit be set at $45 per kilowatt of nameplate capacity of the small-power project. In the event the project fails to meet its operation date, delay damages would be calculated based on the difference between the regional market rates for electricity and the rates in the power purchase agreement.

Requiring new projects to pay the difference between market and contracted rates ensures the utility and its customers won’t be paying extra if the utility has to buy power on the market or generate itself to make up for the lost power due to the project’s failure to meet its online date. Projects have 120 days to cure their default before the agreement may be terminated.

Nov. 20, 2012: A majority of FERC announces it will initiate an enforcement action in federal district court against the Idaho Commission for the PUC’s denial of power purchase agreements between Idaho Power and the three Murphy projects. FERC said the Idaho Commission violated PURPA by limiting the circumstances under which a regulated utility is legally obligated to purchase power from a QF.

Specifically, FERC said the Idaho Commission "overlooked the fact that a legally enforceable obligation may be incurred before the formal memorialization of a contract in writing."

The PUC argued that modifying the Murphy order was inappropriate because the projects' new owner, First Wind, failed to timely seek reconsideration or appeal the PUC's June 2011 order disapproving the projects. *(See Oct. 12, 2012.)* First Wind's petition, filed nearly 15 months after the reconsideration deadline, represents an attempt by new owners to resurrect a long-dead claim, the commission stated. "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 the Cedar Creek projects. The two are not the same. In the Cedar Creek case, the project timely appealed and a settlement between all the parties was subsequently approved by the PUC and that project is going forward."

A FERC commissioner's dissent noted that in previous cases, entities petitioning FERC have access to federal courts to pursue enforcement efforts. "In this order, (FERC) has chosen to expend federal resources to enforce the claims of a single wind developer. ... (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."

December 18, 2012: The Commission issues a final order in the GNR-E-11-03 docket. The key points:

- The cap for wind and solar projects seeking the commission's published avoided-cost rates remains at 100 kW. The eligibility cap for all other QFs remains 10 average megawatts. Wind and solar projects larger than 100 kW are eligible for a negotiated avoided-cost rate using each utility's Integrated Resource Plan, as the basis for the negotiation. The commission denied an Idaho Power Company proposal to use the IRP-based negotiated rate methodology for all QFs.
- The commission denied a proposal by Idaho Power that would relieve it from its PURPA mandatory purchase obligations by allowing it to curtail generation from some projects during certain periods of light customer load. The commission said that while federal law allows curtailment under specified conditions, Idaho Power did not provide sufficient evidence to support its proposal.
- Projects with published-rate contracts will be able to keep the Renewable Energy Certificates (RECs or "green tags") associated with their projects. Wind and solar projects larger than 100 kW and all projects larger than 10 average megawatts with negotiated contracts using the IRP methodology will retain one half of the RECs associated with their project while the purchasing utility retains the other half.
- Fuel price forecasts and load forecasts will be updated on June 1 of each year so that the price paid QFs more accurately reflects avoided cost. Up until now, a large part of the rate paid QFs was updated only when the Northwest Power Planning and Conservation Council issued an updated natural gas price forecast. The new annual update will be based on natural gas price forecasts provided by the federal Energy Information Administration's Annual Energy Outlook.
- The maximum contract length for sales agreements between utilities and QFs remains 20 years. Utilities argued for five years. Alternatives to a 20-year contract may be negotiated by the parties and considered by the commission.
- New QF contracts will be paid for capacity based only on the project's ability to deliver during peak hours and when a utility's long-range plan shows the utility is capacity deficient. Currently, QFs are paid for both energy and capacity, the latter being potential surplus the utility may need during peak-load hours.

Other electric cases

Case No. IPC-E-11-11, Order No. 32425
January 6, 2012

Commission accepts Idaho Power long-range growth plan

The commission has accepted a long-range planning document from Idaho Power Company, but expects the company to continue to address issues raised by the commission and environmental organizations.

Those issues include the company's continued involvement in the Gateway West transmission line project, evaluating the potential for early retirement of coal plants, the progress of a solar demonstration project and the federal relicensing of the Hells Canyon hydro projects.

The commission requires Idaho's electric and gas utilities to file an Integrated Resource Plan (IRP) every two years detailing how the utilities plan to meet customer demand in 10- and 20-year windows. The commission accepts or rejects the IRP for planning purposes only. The plan may change as circumstances warrant and proposed projects in the plan are considered later on a case-by-case basis when and if they are formally proposed.

Idaho Power expects its customers to increase from 492,000 in 2010 to more than 650,000 by the end of 2030. Average load is expected to increase by 29 average megawatts (1.4 percent annually) by 2030. Summer peak hour loads are expected to increase by 69 megawatts (1.8 percent annually).

Idaho Power's plan continues its emphasis on reducing load through energy efficiency measures and programs that reduce demand by shifting large industrial or irrigation loads off peak-use times. The utility plans to reduce load by 233 average megawatts annually by 2030 through energy efficiency programs and reduce demand by 351 megawatts by summer 2016.

The utility also expects to have 450 MW available in market purchases of power once the Boardman to Hemingway transmission project is completed, anticipated in 2016.

Long range, the company is looking to completion of a 170-MW single-cycle natural gas plant in 2022 and possibly a 300-MW combined-cycle natural gas plant in 2025. The company also hopes to obtain 52 MW in geothermal generation, 50 MW from a solar power tower and 60 MW from small hydroelectric projects in 2021 through 2030.

The public is included in the process of writing the company's IRP. Members of environmental organizations, major industrial customers, agricultural interests, state legislators, PUC staff and representatives from the state Office of Energy Resources and Northwest Power and Conservation Council participate as members of the Integrated Resource Plan Advisory Council.

The Idaho Conservation League (ICL), Renewable Northwest Project (RNP) and Snake River Alliance (SRA) said the company's plans to upgrade its Jim Bridger coal plant but does not provide details on the costs of that strategy as opposed to using alternative sources of generation rather than upgrading the coal plant.

RNP and SRA also said Idaho Power should consider alternatives other than a natural gas plant if the Boardman to Hemingway transmission line is not completed. That 300-mile, 500-kilvolt transmission line from Boardman, Oregon to Melba, is expected to improve access to markets, meet peak summer capacity needs and increase reliability for Idaho Power customers.

Commissioners from Power County and Cassia County said Idaho Power should reconsider its joint commitment with Rocky Mountain Power to build the Gateway West transmission line from northeastern Wyoming, through south-central Idaho and ending near Melba. The commissioners say reduced electrical demand and growing doubt that Congress will approve carbon restricting legislation such as a carbon tax or a cap-and-trade system diminish the need to build the 1,100-mile line.

Idaho Power states that increased generation from hydro sources and reduced coal-fired generation have allowed the utility to make progress on its goal to reduce carbon emissions and "emissions intensity" (measured in pounds per megawatt-hour) by 15 percent through 2013. Idaho Power has more than 1,100 MW of coal resources jointly owned with other utilities in three states: Wyoming (Jim Bridger plant), Nevada (Valmy) and Oregon (Boardman). In 2007, Idaho Power decided not to pursue development of a coal resource in its 2006 IRP and does not include any new coal generation in the 2011 IRP. The Boardman plant is scheduled for decommissioning in 2020.

In 2010, 48.8 percent of Idaho Power's generation came from hydroelectric sources, while 43.9 percent came from coal. By 2030, the utility anticipates that 53 percent of its generation will come from hydroelectric sources and 26 percent from coal.

Both ICL and RNP question the company's intent to issue bids to build an up to 1-megawatt solar demonstration project. The project would test new photovoltaic panel technologies, inverters and other mounting and tracking systems. ICL claims a better step would be to address issues related to solar development including interconnection, net metering standards and integrating distributed systems. A demonstration project should be focused on rooftop solar, ICL claims.

RNP recommended that the company consider geographic dispersion of several solar projects. RNP claims solar PV is already a mature technology, lessening the need for most of the information Idaho Power hopes to obtain from its demonstration project.

ICL notes that Idaho Power has recorded $153 million in relicensing expense for the Hell Canyon complex through March 2011. ICL is asking for a "more robust discussion of the company's efforts and strategy to resolve the relicensing process in a timely manner."

Two projects from the 2009 IRP are under way. The 300-MW Langley Gulch natural gas plant being built near New Plymouth is scheduled to be online in mid-2012. An upgrade to the Shoshone Falls hydroelectric project, which will provide another 49 MWs, is to be completed in 2016.

Case No. IPC-E-11-14, Order No. 32453
February 10, 2012

Idaho asserts "primary" jurisdiction over wind power transactions

The Idaho commission said it has primary jurisdiction over proposed power sales agreements between Idaho Power Company and two Idaho-based wind projects that want to sell their output to Idaho Power customers in Oregon where the developers can receive higher rates. The projects are qualifying facilities under the provisions of PURPA.

Because Idaho Power customers (95 percent in Idaho and 5 percent in Oregon) would end up paying Oregon's higher avoided-cost rate, Idaho Power sought a declaratory order from the Idaho Public Utilities Commission that would assert Idaho eligibility requirements and rates over the projects rather than Oregon's. In Idaho, the projects are too large to qualify for the state published rate meaning the project developers and the utility would have to negotiate an avoided-cost rate based on a formula approved by the commission. In Oregon, the projects do qualify for that state's published rate.

In response to Idaho Power's petition, the commission ruled that both the Idaho commission and the Public Utility Commission of Oregon have jurisdiction over PURPA transactions, but that the Idaho commission, given the location of the projects and their desire to interconnect with Idaho Power, has primary jurisdiction. "Given the facts of this case, we find that Idaho is the more appropriate jurisdiction to exercise authority" over the transactions, the commission said. "However, we cannot and will not order the projects to submit themselves to this commission's jurisdiction."

State commissions cannot compel projects to sell their output to a specific utility. However, to be able to compel a utility to buy from it, a small-power producer must either sell directly to the utility it interconnects with or request that the directly interconnected utility transmit the output to any <u>other</u> electric utility. In this case, the developers request that the projects' output be wheeled to the same utility, but only to its customers in Oregon, in order to qualify for that state's higher published rate. "The projects seek to interconnect with Idaho Power in Idaho and compel the <u>same</u> utility to transmit the output for delivery to a substation located in another state that has preferable avoided-cost rates," the commission said, which is not permissible under Federal Energy Regulatory Commission (FERC) regulations.

Idaho Power claimed the Boise-based developers of both projects attempted to "cherry pick" a different jurisdiction's rates for its Idaho projects. "This is a blatant attempt to manipulate and avoid the Idaho commission's rates, rules and regulations that are designed to implement PURPA and protect Idaho Power's customers," the company stated.

The developers argued the commission is prohibited by federal law from regulating qualifying PURPA projects and does not have authority to restrict the projects' access to markets. Doing so, the developers argued, would violate the Commerce Clause by restricting the projects' access to markets outside Idaho.

The commission disagreed, stating "sound public policy suggests that the Idaho commission should exercise primary jurisdiction over the two transactions. Western Desert and Tumbleweed are projects located within Idaho seeking to interconnect with Idaho Power's Idaho service territory. The costs associated with PURPA transactions – regardless of the jurisdiction approving the agreements and avoided-cost rates – are borne primarily by Idaho ratepayers as compared to Oregon ratepayers."

Case No. IPC-E-11-26, Order No. 32462
February 24, 2012

Commission approves Idaho Power agreement with wind project

The commission approved a 20-year sales agreement with High Mesa Energy LLC, a 40-megawatt wind project near Bliss. High Energy, based in West Des Moines, Iowa, states the project will be operating by Dec. 28, 2012.

The developer will be paid a 20-year levelized price of $56.43 per megawatt-hour, though the pricing stream varies based on the time of year and the time of day that energy is delivered to Idaho Power. The agreement also states that the value of the Renewable Energy Certificates generated over the 20-year contract will be shared equally by the developer and Idaho Power.

Commission staff calculated a lower avoided-cost – about $3 per MWh lower or 5 percent – than that agreed upon by Idaho Power and High Mesa, and, thus, recommended denial of the project. However, the commission said the agreement contains "acceptable contract provisions," and should be approved. Both commission staff and the commission acknowledged that the negotiated IRP methodology is relatively new and that many of the issues related to computing an accurate avoided cost for PURPA projects are being considered in another case now before the commission (GNR-E-11-03). "We expect to see the IRP methodology issues addressed by staff argued more fully and to conclusion in the generic PURPCA docket currently before the commission," the commission said.

Case No. IPC-E-11-25, Order No. 32470
February 24, 2012

PUC approves Idaho Power contract with landfill waste to energy project

Idaho Power Company's 20-year sales agreement with Dynamis Energy LLC's landfill waste to energy project at the Ada County landfill near Boise was approved by the commission.

At maximum capacity, the project will generate 22 megawatts, according to Eagle-based Dynamis. The agreement states the developer will be paid a 20-year levelized price of $92.53 per megawatt-hour, though the pricing stream varies based on the time of year and the time of day that energy is delivered to Idaho Power. The scheduled operation date is Feb. 14, 2014.

Rates in the agreement may appear high, commission staff noted, but the rates are not unreasonable given that all of the plant's energy will be delivered during peak hours when energy is substantially more valuable. Further, unlike many renewable projects such as wind and solar which are intermittent, all of this project's energy will be available during peak-load hours in the summer.

Commission staff said the rates contained in the agreement are not a precise reflection of Idaho Power's avoided costs and may even be too low. Dynamis maintained that staff's recommended adjustments are either not immediately quantifiable or would have a minor impact on the contract's rates. Dynamis agreed to waive any later determination that the contract rate may be too low. The commission concluded that the agreement "contains acceptable contract provisions," and is in the best interest of the parties and ratepayers.

The commission received about 27 written comments, 16 of those opposed, alleging the project's technology is untested and the rate is too high.

Regarding whether the technology will work, the commission noted that all power purchase agreements it approves contain provisions to protect ratepayers if the project fails to perform. "Significantly, no payments are made by Idaho Power to Dynamis unless energy is delivered," the commission said. The agreement also includes liquidated damage provisions if the facility is not brought on line by Feb. 14, 2014.

Some of those commenting objected to Ada County's approval of the project. The commission said its review is focused on whether the agreement meets PURPA and other state and federal regulations. "Consideration of Ada County's role in this project is outside our authority. We take no position on the commenters' expressed frustration with Ada County's processes and decision-making regarding this project," the commission said.

The agreement also states that the value of the Renewable Energy Certificates that would be generated over the 20-year contract will be shared equally by Dynamis and Idaho Power.

Case No. IPC-E-11-24, Order No. 32472
March 6, 2012

Commission OKs changes to Idaho Power line extension tariff

All overhead costs related to new service attachments for Idaho Power customers will be paid by the customers requesting the construction, according to a commission order.

The commission's order removes a 1.5 percent cap on the amount Idaho Power can collect on its "Rule H tariff" in overhead expense for line extensions. After charging 1.5 percent of overhead costs to the new customers, the rest of the expense was included in rates paid by the general body of ratepayers.

The commission's order is an effort by both the company and regulators to shift more of costs related to growth to the cause-causers. "We have repeatedly stated that customers requesting Rule H line extensions should bear the costs of those extensions," the commission said. "By requiring customers who request services to pay for the costs of those services, it relieves one area of upward pressure on rates."

Currently, the Rule H tariff provides that overhead costs, such as pay and expenses for engineering supervisors and administrative workers, be pooled and recouped through an assessment placed on line extension work orders. The tariff caps the collection for overhead at 1.5 percent. The rest of the current overhead rate of 17.5 percent (15.5 percent) was included in base rates for all customers. The updated tariff, effective March 15, increases the overhead rate to 21.5 percent and allocates the entire cost to customers requesting the extension.

Idaho Power sought to have the overhead rate adjusted monthly if needed to balance the company's overhead account. The commission did not approve the monthly change, but said the company could update its overhead rate each year as it updates other Rule H-related expenses.

Case No. IPC-E-12-05, Order No. 32499

March 27, 2012

Commission OKs new Idaho Power pricing plan

A new pricing option for a limited number of Idaho Power Company residential customers will allow them to pay less for electricity if they shift more of their electrical use to late night and weekend hours.

The commission approved Idaho Power's proposal to offer its Time Variant Pricing Plan to 1,200 volunteer customers. After submitting a report to the commission on its 2012 results, the utility may be able to expand the plan to more customers next year.

Shifting demand on Idaho Power's system away from on-peak hours can reduce power supply expense to the utility and delay or eliminate the need to build new power plants, all of which reduces expense for customers, even those who don't directly participate in the program.

Commission staff, the Idaho Conservation League, the U.S. Green Building Council Idaho (USGBCI) and the Snake River Alliance endorsed the pricing plan. USGBCI said the plan will "advance energy efficiency and reduce the utility's need to purchase expensive power on the open market to meet high peak demand."

A smaller-scale plan, called Time-of-Day, is now offered (under the company's Schedule 5 tariff) in the Emmett area. With the installation of automated meters throughout Idaho Power's service territory, the plan can now be expanded to include more customers.

During the non-summer months, customers on the standard Schedule 1 residential tariff pay 6.83 cents per kWh for the first 800 kWh of use, 7.58 cents for use between 801 kWh and 2,000 kWh and 8.46 cents for use of 2,001 kWh and more. Under Time Variant Pricing, customers will pay 6.26 cents per kWh during off peak hours and 8.22 cents during peak hours. Peak hours are 1 to 9 p.m. on weekdays. All other hours, including all weekend hours, are off-peak.

During the summer months, residential customers pay 7.4 cents for the first 800 kWh; 9 cents for consumption between 801 and 2000 kWh and 10.8 cents for use above 2,000 kWh. Under Time Variant Pricing, customers will pay 6.26 cents per kWh for off-peak use and 11.35 cents for on-peak use.

Idaho Power will send up to 60,000 invitation letters to customers in the Treasure Valley area (where automated meters have been in place 12 months or longer) with the hope of getting 1,200 participants.

Customers invited to participate will have access to an online Energy Use Advising Tool that will calculate their monthly and annual bills under the standard Schedule1 tariff the last 12 months. With the use of a calculator provided, the company will help customers determine the impact on their bills if they use energy the same as the previous year or if they can shift a percentage of their use to off-peak hours.

The company also proposes to make the tariff available to owners of electric vehicles throughout its southern Idaho territory by providing educational materials about the pricing plan to car dealerships. Under the plan, electric car owners could charge their cars during off-peak hours which could reduce their bills as well as reduce the negative impact of this new end-use load on Idaho Power's grid.

Case No. IPC-E-11-19, Order No. 32505
April 2, 2012

Decoupling mechanism made permanent, but adjustments coming

An Idaho Power Company pilot program that allows the utility to recover its fixed costs of providing power no matter how much revenue is lost as a result of energy conservation is being made permanent.

The commission is allowing the Fixed Cost Adjustment mechanism (FCA), formerly a pilot program, to continue as a yearly adjustment to the rates of Idaho Power's residential and small-business customers. The FCA has lowered rates once and increased them three times since 2007, though adjustments have been minor. However, the commission is asking Idaho Power to file a proposal in six months to address how reductions in consumption that aren't directly related to energy conservation should be treated.

Regulated utilities have a built-in disincentive to invest in energy efficiency and conservation programs because they lose revenue when electric consumption declines. To remove that disincentive, the Fixed Cost Adjustment, which can be no higher than 3 percent, is designed to ensure the company recovers its fixed costs of serving customers regardless of the amount of energy conservation. Often referred to as "decoupling," the FCA decouples the link between energy efficiency and energy sales.

If the actual fixed costs recovered from customers by Idaho Power are less than the fixed costs authorized in the most recent rate case, residential and small-commercial customers get a surcharge. If the company collects more in fixed costs than authorized by the commission, customers get a credit.

The following is the average monthly rate impact of the FCA for residential and small-business customers in the years from 2007 through 2011:

2007 – 48-cent reduction
2008 – 56-cent increase
2009 – $1.28 increase
2010 – $1.89 increase
2011 – 24-cent increase (proposed)

For the 2011 FCA, Idaho Power is asking for a 0.28 percent increase effective June 1. The utility claims it under-collected the fixed costs it was allowed in the last rate case by $8.83 million from residential customers and by $1.48 million from small-business customers.

All parties participating in the case endorsed making the program permanent, but commission staff proposed that the FCA balancing account be equally shared between customers and company. Commission staff said that Idaho Power reports indicate that energy savings from company programs accounted for between 24 and 43 percent of reduced consumption and that other factors, such as the economy, contributed toward reduced power use.

The Idaho Conservation League said that while staff's observation may be true, there are other benefits to the FCA mechanism, such as reduced risk to the company and its customers by ensuring Idaho Power's revenues and its returns are stable, which, in turn, incents cost controls. ICL said the revenue stability ensured by the FCA decreases the company's incentive to promote sales. The Northwest Energy Coalition also argued against staff's cost-sharing proposal, asserting that the change in the FCA mechanism shifts the risks of sales volatility back to both the utility and its customers.

Idaho Power also opposed the commission staff proposal to share the FCA deferral balance. Staff's recommendation compromises the regulatory framework that "paved the way for Idaho Power's aggressive and successful pursuit" of cost-effective energy efficiency programs.

Since implementation of the FCA, energy savings have increased from 62,544 megawatt-hours in 2007 to 163,315 MWhs in 2011. The amount of energy saved during 2011 was enough to power more than 12,900 average homes. Programs designed to reduce demand on the company's system have increased from 50 MW of reduction in 2007 to 403 MW in 2011. Energy efficiency is the least expensive energy source for utilities. Program that encourage reductions in energy demand and more efficient use of energy can delay or defer the utility's need to build more power plants or buy energy from more expensive resources.

In its ruling, the commissioners said there is no dispute that the FCA does not isolate or identify changes in cost recovery associated solely with the company's energy efficiency programs. "Staff's sharing proposal may have merit, but there is not a sufficient record to support a finding that a sharing of 50/50 between the company and customers is the correct ratio," the commissioners said. Thus, within six months, Idaho Power is directed to file a proposal to adjust the FCA to address the capture of changes in load not directly related to energy efficiency programs.

Case No. IPC-E-12-10, Order No. 32531
May 1, 2012

Complaint by Interconnect Solar dismissed

The developer of a solar project near Murphy filed a complaint against Idaho Power, alleging the utility improperly cancelled its sales agreement with the project and mishandled a study that was to determine where the project would interconnect with Idaho Power's transmission system.

Boise-based Interconnect Solar had a sales agreement with Idaho Power for the 20-megawatt project that was supposed to be online by July 1 of this year. In order to qualify for federal tax incentives, the developer chose an operation date that would come before Idaho Power believed the required interconnection study and transmission construction could be completed. Interconnect Solar agreed to accept the risk and proceed with the project.

An original path proposed for the line met with objections from the Bureau of Land Management because it crossed along the Oregon Trail and within protected raptor nesting areas. Setbacks regarding interconnection and transmission caused Interconnect Solar to miss a payment deadline. Interconnect Solar's agreement was terminated by Idaho Power because the project failed to post a required delay security. Interconnect Solar maintained it could not get a loan to post the delay security because BLM objected to the original path, which left the project without a valid interconnection agreement.

At the time the sales agreement was approved, the commission expressed concern regarding the project's choice for a commercial operation date. The September 2011 order approving the agreement stated, "We share the concerns of the commission staff and Idaho Power regarding Interconnect Solar's choice of a scheduled operation dates that precedes Idaho Power's estimated date for completion of the projects' interconnection. The project's optimism may be foolhardy. Interconnect Solar maintains its position that interconnection will occur ahead of Idaho Power's estimated schedule at its own peril."

Case No. IPC-E-10-22, Order No. 32601
August 3, 2012

PUC approves settlement between biomass project, Idaho Power

The commission approved a settlement between Idaho Power Company and the developer of an Emmett biomass power project regarding the project's failure to meet scheduled operation dates.

Under the settlement, Montana-based Yellowstone Power will pay Idaho Power $200,000 in non-performance damages in exchange for Idaho Power's agreement to not draw on a current $450,000 Letter of Credit against the project. If Yellowstone fails to make the payment, then it agrees to allow Idaho Power to draw on the Letter of Credit.

"The settlement stipulation acknowledges Yellowstone Power's default under the terms of the agreement, recognizes the complications in calculating actual damages and avoids costly litigation," the commission said.

Yellowstone Power developer Richard Vinson and Idaho Power reached a sales agreement in May 2004 under which Idaho Power would buy the energy from a 17.5-megawatt power generation project at the site of the former Boise Cascade Plant near Emmett. The project was a biomass-fueled combined heat and power plant co-located with the sawmill. Energy would be generated from the steam created by the controlled burning of the woody biomass fuel.

When that project failed to meet its scheduled operation date, the parties agreed to a smaller 11.5-MW project at the same site when the Emerald Forest Products sawmill opened in May 2010. That agreement, approved in August 2010, stipulated that $106,804 in non-performance damages from the previous project was to be offset against the energy payments Yellowstone was to receive from the smaller project.

In May this year, Idaho Power sent Yellowstone a Notice of Material Breach for failing to meet the Dec, 31, 2011, online date for the smaller project. Yellowstone Power claimed a force majeure event – the failure of the sawmill to continue operations – as the reason for not meeting its online date.

Case No. IPC-E-12-15, Order No. 32667
October 23, 2012

PUC finds demand-side management expenses 'prudently incurred'

The commission has reviewed more than $42 million in expenses incurred by Idaho Power Company to promote energy efficiency and reduce demand. The commission determined that the vast majority of those expenses were prudently incurred.

That determination does not impact customer rates, but signals the commission's approval for the expenses incurred to operate 20 demand-side management (DSM) programs funded by a 4 percent rider on customer bills. Seventeen of the programs offer customers financial incentives to use their energy more efficiently while three of the programs reduce demand on the company's system by shifting energy use to off-peak times of the day.

The programs must pass multiple cost efficiency tests that demonstrate that DSM savings are greater than the programs' costs. One of the tests must reflect a savings to all customers, not just those who directly participate in the programs. Reduced energy demand and energy used more efficiently lessens the need for Idaho Power to have to generate the power itself or acquire it from more costly resources, and it offsets the need for the utility to build new resources. The commission's prudency review helps establish that without these programs in place, customer bills would be even higher.

During 2011, Idaho Power achieved 179,424 megawatt-hours of energy savings, or enough energy to service more than 12,900 average homes for a year. Some of the efficiency programs include financial incentives for customers to invest in efficient lighting, in Energy Star® products and heating and cooling efficiencies. The three demand-reduction programs, such as air conditioner cycling and irrigation load control, provide customers incentives to shift their energy consumption to hours of the day when demand on Idaho Power's generation system is not as great. Those programs reduced demand by 403 megawatts, a 20 percent increase over 2010 levels.

The commission did not include about $89,600 in expense related to labor expense increases for Idaho Power employees whose salaries are funded by the energy efficiency rider. The commission did not say those expenses are not justifiable, but that they did not receive the same scrutiny that employee wages and benefits in other sectors of the company receive during a general rate case. Idaho Power was given more time to provide more information to determine whether the increase in the labor-related expense is reasonable when compared to the benefits those expenses achieve.

Also not included was $82,855 in expense related to Idaho Power's air conditioner cycling program. Equipment and software needed to operate the program was not functioning properly and should have been more carefully monitored, the commission said.

The commission denied about $212,340 in carrying charges from interest accrued on incentive payments made to customers with custom-made efficiency programs. The amount of carrying charge allowed is an issue that should be determined in a general rate case, the commission said.

The commission also directed Idaho Power to expand participation from members of the company's Energy Efficiency Advisory Group (EEAG), a 12-member committee representing customer groups and other interested parties that advises the company on its energy efficiency programs. The commission said the company should encourage questions and feedback from all attending stakeholders, not just EEAG members.

"DSM programs and measures are powerful tools that help customers manage their energy consumption and mitigate the impact of potential rate increases," the commission said. "In recognition of this, we direct Idaho Power to expand participation in the EEAG." The commission said the company should increase customer awareness of energy efficiency programs and improve "customers' energy I.Q."