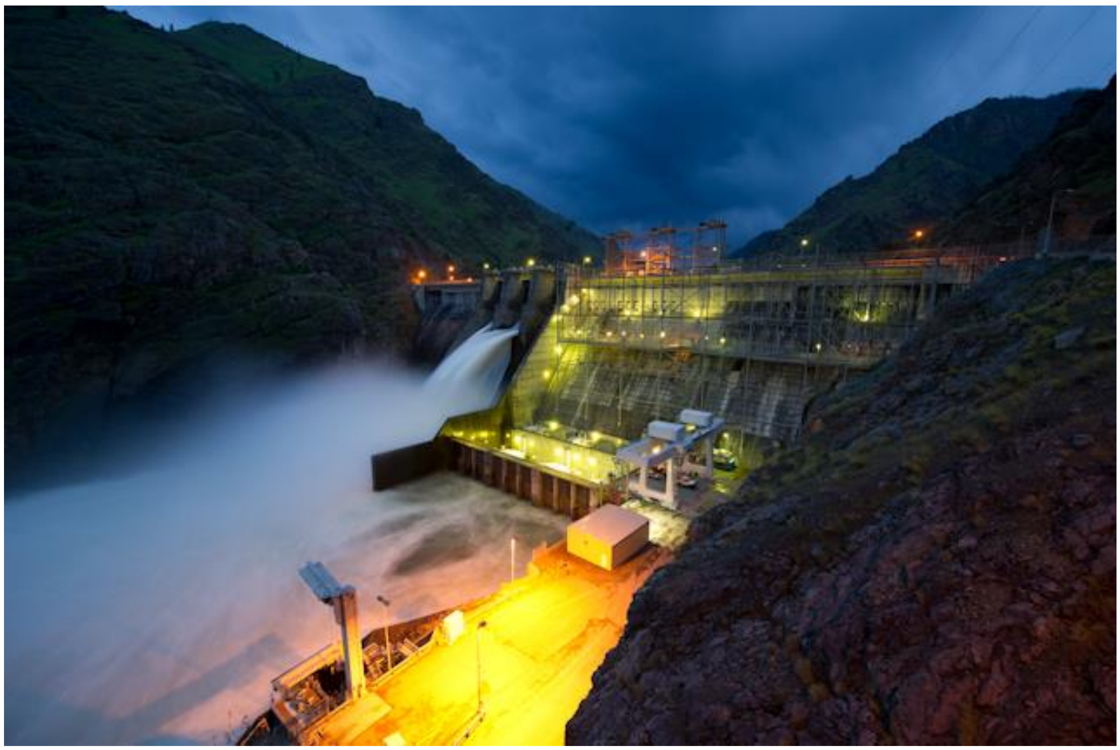
IDAHO PUBLIC UTILITIES COMMISSION



2015 ANNUAL REPORT

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IDAHO PUBLIC UTILITIES COMMISSION

Contact us: 208-334-0300 **Website:** www.puc.idaho.gov

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Outside Boise, Toll-Free Consumer Assistance	1-800-432-0369

Idaho Telephone Relay Service (statewide)

Voice:	1-800-377-3529
Text Telephone:	1-800-368-6185
TRS Information:	1-800-368-6185

This report and all the links inside can be accessed online from the Commission's Website at www.puc.idaho.gov. Click on "File Room," in the upper-left-hand-corner and then on "IPUC 2015 Annual Report."

Front cover photograph courtesy of Idaho Power Company.

Idaho Public Utilities Commission

P.O. Box 83720, Boise, ID 83720-0074

C.L. Butch Otter, Governor

Paul Kjellander, Commissioner
Marsha Smith, Commissioner
Kristine Raper, Commissioner

December 1, 2015

The Honorable C.L. "Butch" Otter
Governor of Idaho
Statehouse
Boise, ID 83720-0034

Dear Governor Otter:

It is my distinct pleasure to submit to you, in accordance with Idaho Code §61-214, the Idaho Public Utilities Commission 2015 Annual Report. This report is a detailed description of the most significant cases, decisions and other activities during 2015. The financial report on Page 9 is a summary of the commission's budget through the conclusion of Fiscal Year 2015, which ended June 30, 2015.

It has been a privilege and honor serving the people of Idaho this past year.

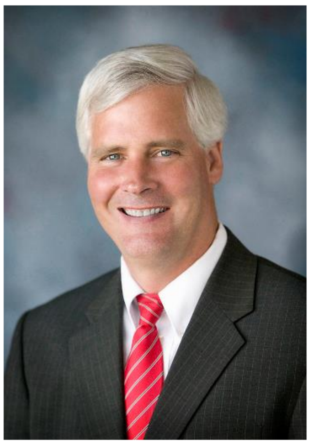
Sincerely,

Paul Kjellander

President, Idaho Public Utilities Commission

COMMISSIONERS

PAUL KJELLANDER



Paul Kjellander rejoined the Idaho Public Utilities Commission in April 2011 following his service as administrator of the Office of Energy Resources (OER). Kjellander, who serves as Commission president, was appointed to his current six-year term by Idaho Governor C.L. “Butch” Otter.

Kjellander previously served on the Commission from January 1999 until October 2007. In 2007, Governor Otter appointed Kjellander to head up the newly created OER. During his 3.5 years at OER, Kjellander created an aggressive energy efficiency program funded through the federal stimulus act. Kjellander was also elected to serve as a board member on the National Association of State Energy Officials.

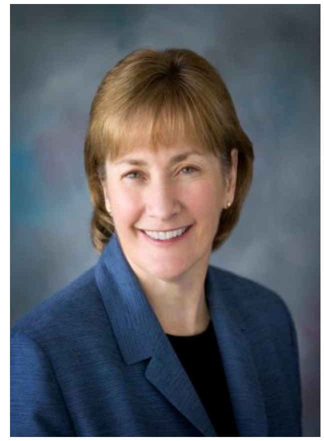
Kjellander, a Republican, was elected to three terms (1994-1999) in the Idaho House of Representatives, where he served as a member of the House State Affairs, Judiciary and Rules, Ways and Means, Local Government and Transportation committees. During his last term in office, Kjellander was elected House Majority Caucus Chairman. His legislative service includes membership on the Legislature’s Information Technology Advisory Council and the House/Senate Joint Committee on Technology. He also served as co-chairman of the Legislative Task Force on the Federal Telecommunications Act of 1996 and vice chairman of the Council of State Governments-West “Smart States Committee.” His interim legislative committee assignments included the Optional Forms of County Government Committee, Capital Crimes Committee and the Private Property Rights Committee.

Kjellander has also served as director of Boise State University’s College of Applied Technology Distance Learning, program head of broadcast technology, station manager of BSU Radio Network, director of the Special Projects Unit for BSU Radio, and BSU Radio’s director of News and Public Affairs. Kjellander’s undergraduate degrees from Muskingum College, Ohio, are in communications, psychology and art. He has a master’s degree in telecommunications from Ohio University.

As a member of the National Association of Regulatory Commissioners (NARUC), Kjellander has served on the Telecommunications, Consumer Affairs, and Electricity Committees. He also served as Chairman of the Joint Board on Jurisdictional Separations. Kjellander is a member of the NARUC Presidential Federalism Task Force and serves as vice chairman of the NARUC Telecommunications Committee. He is currently serving as a NARUC representative to the North American Numbering Council.

Kjellander is a licensed youth soccer coach and has qualified teams for various state and regional tournaments.

MARSHA SMITH



Commissioner Smith returned to the commission on an interim basis on July 30, 2015, following the untimely passing of Commissioner Mack Redford. Appointed by former Gov. Cecil Andrus in 1991, she served four terms until her retirement in February 2015. Just five months after her retirement, she was re-appointed by Gov. C.L. “Butch” Otter to serve through December 2015 to allow the Governor and Legislature time to appoint and confirm a new commissioner to fill out the remainder of Commissioner Redford’s term.

Commissioner Smith represented Idaho on the Western Interconnection Regional Advisory Body and the State-Provincial Steering Committee. She is past chair of the Western Electricity Coordinating Council and a past president of the National Association of Regulatory Utility Commissioners (NARUC). She served on the NARUC Board and is a past chair of the association’s Electricity Committee. She was also a member of the Steering Committee of the Northern Tier Transmission Group. She chaired the Western Interstate Energy Board’s Committee for Regional Electric Power Cooperation from October 1999 to October 2005. She was a member of the National Council on Electricity Policy Steering Committee, the Harvard Electricity Policy Group and is a member of the Idaho State Bar.

Smith received a Bachelor of Science degree in biology/education from Idaho State University, a master of library science degree from Brigham Young University and her law degree from the University of Washington.

Before joining the commission, Commissioner Smith served as a deputy attorney general in the business regulation/consumer affairs division of the Office of the Idaho Attorney General. She became a deputy attorney general for the commission in 1981 and was chair of the NARUC Staff Subcommittee on Telecommunications. In 1989, she became the commission’s director of policy and external relations until 1991, when Gov. Andrus appointed her to the commission.

A fourth-generation Idahoan, Commissioner Smith has two sons.

KRISTINE (SASSER) RAPER

Kristine (Sasser) Raper was appointed to the commission effective February 19, 2015, by Governor C.L. "Butch" Otter. Commissioner Raper's term expires in January 2021.

Before her appointment, Commissioner Raper served seven years as a deputy attorney general assigned to the Public Utilities Commission. While a deputy attorney general for the PUC, she was involved in electric, gas, water and telecommunications cases. She successfully represented the PUC in Federal District Court against a lawsuit brought by the Federal Energy Regulatory Commission. That matter resulted in a settlement between the parties.

Before her work in the Attorney General's office, she served for eight years as a law clerk to Commissioner R.D. Maynard on the Idaho Industrial Commission. Raper developed expertise in Idaho workers' compensation law and unemployment law matters appealed through the state Department of Labor.

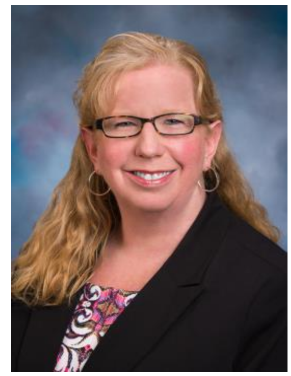
Commissioner Raper was born in Delaware and moved to Utah with her family in the early 1980s. She spent the summer between high school graduation and the start of college working in Grand Teton National Park. She moved to Boise in 1990 to attend Boise State University. In 1995, she earned a Bachelor of Science in criminal justice from BSU and in 2001 received her juris doctor from the University of Idaho.

Commissioner Raper serves on the Electricity Committee of the National Association of Regulatory Utility Commissions.

The commissioner and her husband, Mark, share three children.

Commission Changes

Governor Otter appoints Kristine Raper to six-year term on Idaho Public Utilities Commission



Feb. 19, 2015 – Idaho Governor C.L. “Butch” Otter this week announced the appointment of Kristine (Sasser) Raper to a six-year term on the Idaho Public Utilities Commission. While Raper’s term officially begins today, her appointment is subject to confirmation by the Idaho State Senate.

Raper, 43, succeeds Commissioner Marsha Smith, who is retiring after serving four terms as a commissioner and nearly 35 years in state government.

Before her appointment to the commission, Raper served for seven years as a state deputy attorney general assigned as legal counsel to the Public Utilities Commission. She represented the commission on two cases that were appealed to the state Supreme Court and one case in federal district court.

Prior to her work in the attorney general’s office, she served for eight years as a law clerk to Commissioner R.D. Maynard of the Idaho Industrial Commission.

Raper was born in Delaware and moved to Utah with her family in the early 1980s. In 1995, she earned a Bachelor of Science degree in criminal justice from Boise State University and in 2001 received her juris doctor from the University of Idaho.

Raper serves with Commission President Paul Kjellander and Commissioner Mack Redford on the three-member commission.

“I’m pleased to be appointed by Governor Otter to serve the citizens of Idaho in this important role. I will work diligently alongside President Kjellander and Commissioner Redford to continue the PUC’s tradition of integrity and fairness,” Raper said. “Commissioner Marsha Smith served the state and the commission with great distinction and it is an honor to succeed her.”

In his statement, Gov. Otter said, “Over the past seven years, Kristine has distinguished herself as someone who is thorough, professional, collegial and devoted to fulfilling the vital role of an ombudsman for ratepayers and regulator for our public utilities. The electricity, natural gas and other services enjoyed by Idaho citizens are in good hands with Kristine’s knowledge, skills and temperament ensuring that our system works.”

Idaho PUC Commissioner Mack Redford passes away

July 1, 2015 - The Public Utilities Commission and the State of Idaho lost an outstanding public servant with the passing of Commissioner Mack Redford Tuesday, June 30.

Since Gov. C.L. "Butch" Otter appointed him to the Commission in 2007, Mack served the commission with dedication and genuine enthusiasm. All those who worked with Mack were impressed with his interest in PUC-related issues and in his ability to add a personal touch to the work environment.

Mack made a practice of visiting the offices of his co-workers regularly. During contested cases that came before the Commission, Mack treated all parties with fairness and respect. A diehard Vandal, he was gracious even to Bronco fans.

"Mack was the true embodiment of what it means to be a public servant," said Governor Otter. "His wealth of international business experience coupled with his numerous positions inside government gave Mack the kind of insight and combination of skills that is extremely difficult to find and even harder to replace. The people of Idaho lost a true champion and I have lost a good friend. The First Lady and I are keeping Mack, his wife Nancy, and their family in our prayers."

At the time of his appointment, Commissioner Redford, 77, practiced law for the Boise-based firm of Elam & Burke PA, specializing in commercial transactions, construction and engineering law, mediation, real estate and general business.

Commissioner Redford grew up in the Weiser and Caldwell areas, graduating from Caldwell High School. He received both his bachelor's and law degree from the University of Idaho and in 1967 became a deputy in the Idaho attorney general's office. In 1977, he became a deputy attorney general for the Trust Territory of the Pacific Islands, headquartered in Saipan, Northern Mariana Islands.

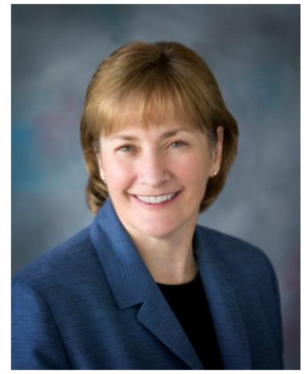
In 1981, Commissioner Redford became general counsel for Morrison Knudsen Engineers and Morrison Knudsen International, a position that took him to Saudi Arabia where MK was building the King Khalid Military City. In 1991, Commissioner Redford was retained by TransManche Link, based in Folkestone, England, where he was legal counsel for the Channel Tunnel Contractors, the builders of the 31-mile Channel Tunnel connecting England and France. It is the second-largest rail tunnel in the world.

In 1992, Commissioner Redford joined the Boise firm of Park Redford & Burkett. In 1993, he was retained by the World Bank of the Government of Nepal as contract and claims counsel for the Arun Ill Hydroelectric Project. In 1996, he became general counsel for Micron Construction, which was later acquired by Kaiser Engineers. He joined the Boise law firm of Elam & Burke in 2001.

He was also very active in community service serving as chair of the Idaho Pardons and Parole Commission, the Board of Directors for Zoo Boise, a volunteer for the Service Corps of Retired Executives and a volunteer in CASA's Guardian Ad Litem program. He was a past president of both the University of Idaho Foundation and the University of Idaho Vandal Boosters.

Commissioner Redford is survived by his wife, Nancy and two children.

Governor to re-appoint Marsha Smith to PUC on an interim basis



July 30, 2015 - Governor C.L. "Butch" Otter announced today that Marsha Smith, a long-time Commissioner for the Idaho Public Utilities Commission (PUC), will be re-appointed to the PUC on an interim basis. Smith fills the Commissioner position left open after Commissioner Mack Redford's sudden passing in June.

"I wish to extend my sincere thanks to Marsha, who after retiring has agreed to step back in to her familiar and valuable role as public servant at a time of need," said Governor Otter. "In the wake of the untimely death of my good friend Commissioner Mack Redford, I can think of no better person to fill that void than Marsha because she knows the issues and has invaluable experience."

Smith's interim appointment period on the PUC is effective immediately and will expire at the end of 2015. At that time, a new commissioner will be appointed to replace her, pending Idaho Senate confirmation. Smith was first appointed to the PUC by then-Governor Cecil Andrus in 1991, and previously served the commission as a deputy attorney general. She served as a Commissioner for 24 years before retiring last February.

"I deeply regret the circumstances that created this vacancy," said Smith. "I am honored to step in on a temporary basis to assist the commission with an unusually heavy case load as well as facilitate a thoughtful process that will allow timely confirmation of a permanent replacement."

Smith re-joins President Paul Kjellander and Kristine Raper on the Commission.

FINANCIAL SUMMARY FUND 0229

Fiscal Years 2011 – 2015

Description	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015
Personnel Costs	$3,275,500	$3,304,100	$3,491,500	$3,528,900	$3,563,500
Communication Costs	$29,300	$29,500	$31,300	$31,000	$23,500
Employee Development Costs	$46,700	$62,500	$55,600	$53,200	$99,200
Professional Services	$12,500	$9,800	$9,700	$12,300	$8,500
Legal Fees	$522,200	$525,300	$551,600	$519,700	$538,400
Employee Travel Costs	$123,300	$115,400	$123,600	$141,100	$152,500
Fuel & Lubricants	$2,900	$4,100	$4,700	$2,700	$5,600
Insurance	$1,300	$1,000	$3,100	$4,400	$4,300
Rentals & Leases	$283,900	$294,200	$276,100	$584,600	$308,600
Misc. Expenditures	$102,100	$85,600	$117,000	$104,700	$84,400
Computer Equipment	$0	$24,300	$29,200	$66,400	$73,600
Office Equipment	$34,400	$0	$13,000	$11,900	$16,500
Motorized/Non-Motorized Equip	$0	$52,300	$0	$0	$32,500
Specific Use Equipment	$0	$0	$0	$0	$0
Total Expenditures	**$4,434,100**	**$4,508,100**	**$4,706,400**	**$5,060,900**	**$4,911,100**
Fund 0229-20 Appropriation	**$4,820,700**	**$4,768,200**	**$4,916,800**	**$5,061,700**	**$5,595,600**
Unexpended Balance	**$386,600**	**$260,100**	**$210,400**	**$800**	**$684,500**

COMMISSION STRUCTURE AND OPERATIONS

Under state law, the Idaho Public Utilities Commission supervises and regulates Idaho's investor-owned utilities – electric, gas, telecommunications and water – assuring adequate service and affixing just, reasonable and sufficient rates.

The commission does not regulate publicly owned, municipal or cooperative utilities.

The governor appoints the three commissioners with confirmation by the Idaho Senate. No more than two commissioners may be of the same political party. The commissioners serve staggered six-year terms.

The governor may remove a commissioner before his/her term has expired for dereliction of duty, corruption or incompetence.

The three-member commission was established by the 12th Session of the Idaho Legislature and was organized May 8, 1913 as the Public Utilities Commission of the State of Idaho. In 1951 it was reorganized as the Idaho Public Utilities Commission. Statutory authorities for the commission are established in Idaho Code titles 61 and 62.

The IPUC has quasi-legislative and quasi-judicial as well as executive powers and duties.

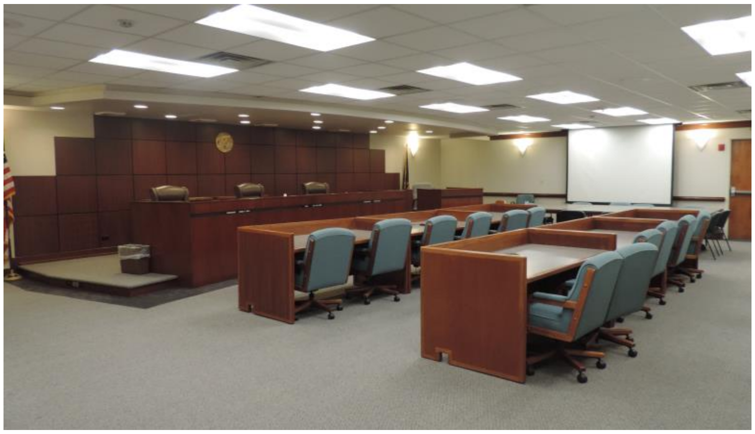
In its quasi-legislative capacity, the commission sets rates and makes rules governing utility operations. In its quasi-judicial mode, the commission hears and decides complaints, issues written orders that are similar to court orders and may have its decisions appealed to the Idaho Supreme Court. In its executive capacity, the commission enforces state laws and rules affecting the utilities and rail industries.

Commission operations are funded by fees assessed on the utilities and railroads it regulates. Annual assessments are set by the commission each year in April within limits set by law.

The commission president is its chief executive officer. Commissioners meet on the first Monday in April in odd-numbered years to elect one of their own to a two-year term as president. The president signs contracts on the commission's behalf, is the final authority in personnel matters and handles other administrative tasks. Chairmanship of individual cases is rotated among all three commissioners.

The commission conducts its business in two types of meetings – **hearings** and **decision meetings**. Decision meetings are typically held once a week, usually on Monday.

Formal **hearings** are held on a case-by-case basis, sometimes in the service area of the impacted utility. These hearings resemble judicial proceedings and are recorded and transcribed by a court reporter.



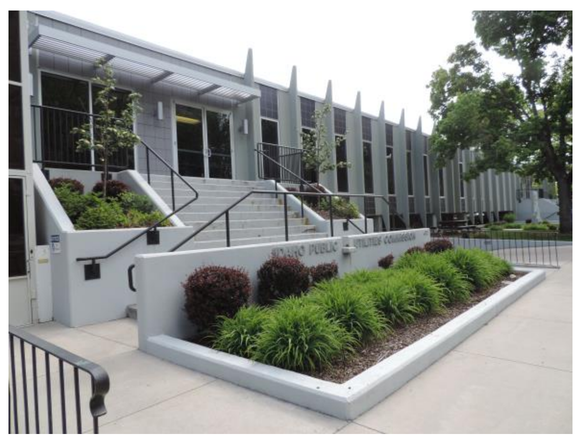
PUC hearing room

There are **technical hearings** and **public hearings**. At technical hearings, formal parties who have been granted "intervenor status" present witness testimony and evidence, subject to cross-examination by attorneys from the other parties, staff and the commissioners. At public hearings, members of the public may testify before the commission.

In 2009, the commission began conducting telephonic public hearings to save expense and allow customers to testify from the comfort of their own homes. Commissioners and other interested parties gather in the Boise hearing room and are telephonically connected to ratepayers who call in on a toll-free line to provide testimony or listen in. A court reporter is present to take testimony by telephone, which has the same legal weight as if the person testifying were present in the hearing room. Commissioners and attorneys may also direct questions to those testifying.

The commission also conducts regular decision meetings to consider issues on an agenda prepared by the commission secretary and posted in advance of the meeting. These meetings are usually held Mondays at 1:30 p.m., although by law the commission is required to meet only once a month. Members of the public are welcome to attend decision meetings.

Typically, decision meetings consist of the commission's review of decision memoranda prepared by commission staff. Minutes of the meetings are taken. Decisions reached at these meetings may be either final or preliminary, but subsequently become final when the commission issues a written order signed by a majority of the commission. Under the Idaho Open Meeting Law, commissioners may also privately deliberate fully submitted matters.



PUC headquarters at 472 W. Washington St., Boise.

Commission Staff

OUR MISSION

- ***Determine fair, just and reasonable rates and utility practices for electric, gas, telephone and water consumers.***
- ***Ensure that delivery of utility services is safe, reliable and efficient.***
- ***Ensure safe operation of pipelines and rail carriers within the state.***

To help ensure its decisions are fair and workable, the commission employs a staff of about 50 people – engineers, rate analysts, attorneys, accountants, investigators, economists, secretaries and other support personnel. The commission staff is organized in three divisions – administration, legal and utilities.

The staff analyzes each petition, complaint, rate increase request or application for an operating certificate received by the commission. In formal proceedings before the commission, the staff acts as a separate party to the case, presenting its own testimony, evidence and expert witnesses. The commission considers staff recommendations along with those of other participants in each case - including utilities, public, agricultural, industrial, business and consumer groups.

Administration

The Administrative Division is responsible for coordinating overall IPUC activities. The division includes the three commissioners, two policy strategists, a commission secretary, an executive administrator, an executive assistant and support personnel.

The **policy strategists** are executive level positions reporting directly to the commissioners with policy and technical consultation and research support regarding major regulatory issues in the areas of electricity, telecommunications, water and natural gas. Strategists are also charged with developing comprehensive policy strategy, providing assistance and advice on major litigation before the commission, public agencies and organizations. ***Contact Wayne Hart, 334-0354 or Gene Fadness, 334-0339, policy strategists.***

The **commission secretary**, a post established by Idaho law, keeps a precise public record of all commission proceedings. The secretary issues notices, orders and other documents to the proper parties and is the official custodian of documents issued by and filed with the commission. Most of these documents are public records. ***Contact Jean Jewell, commission secretary, at 334-0338.***

The **executive administrator** has primary responsibility for the commission's fiscal and administrative operations, preparing the commission budget and supervising fiscal, administration, public information, personnel, information systems, rail section operations and pipeline safety. The executive administrator also serves as a liaison between the commission and other state agencies and the Legislature.

Contact Joe Leckie, executive administrator, at 334-0331.

The **public information office** is responsible for public communication between the commission, the general public and interfacing governmental offices. The responsibility includes news releases, responses to public inquiries, coordinating and facilitating commission workshops and public hearings and the preparation and coordination of any IPUC report directed or recommended by the Idaho Legislature or Governor.
Contact Gene Fadness, public information officer at 334-0339 or Diane Holt, assistant public Information officer, 334-0323.

Legal

Five **deputy attorneys general** are assigned to the commission from the Office of the Attorney General and have permanent offices at IPUC headquarters. The IPUC attorneys represent the staff in all matters before the commission, working closely with staff accountants, engineers, investigators and economists as they develop their recommendations for rate case and policy proceedings.

In the hearing room, IPUC attorneys coordinate the presentation of the staff's case and cross-examine other parties who submit testimony. The attorneys also represent the commission itself in state and federal courts and before other state or federal regulatory agencies. ***Contact Don Howell, legal division director, at 334-0312.***

Utilities Division

The Utilities Division, responsible for technical and policy analysis of utility matters before the commission, is divided into four sections. ***Contact Randy Lobb, utilities division administrator, at 334-0350.***

The **Accounting Section** of seven auditors audits utility books and records to verify reported revenue, expenses and compliance with commission orders. Staff auditors present the results of their findings in audit reports as well as in formal testimony and exhibits. When a utility requests a rate increase, cost-of-capital studies are performed to determine a recommended rate of return. Revenues, expenses and investments are analyzed to determine the amount needed for the utility to earn the recommended return on its investment.
Contact Terri Carlock, accounting section supervisor, at 334-0356.

The **Engineering Section** of three engineers and two utility analysts reviews the physical operations of utilities. The Staff of engineers and analysts develops computer models of utility operations and compares alternative costs to repair, replace and acquire facilities to serve utility customers. The group establishes the price of acquiring cogeneration and renewable generation facilities and identifies the cost of serving various types of customers. They evaluate the adequacy of utility services and frequently help resolve customer complaints.
Contact Rick Sterling, engineering section supervisor, at 334-0351.

The **Technical Analysis Section** of three utility analysts and one economist determines the cost effectiveness of all Demand Side Management (DSM) programs including energy efficiency and demand response. They identify potential for new DSM programs and track the impact on utility revenues. They review utility forecasts of energy, water and natural gas usage with focus on residential self-generation and rate design.
Contact Matt Elam, Technical Analysis section supervisor, at 334-0363.

The **Telecommunications Section** includes two analysts who oversee tariff and price list filings, area code oversight, Universal Service, Lifeline and Telephone Relay Service. They assist and advise the commission on technical matters that include advanced services, 911 and other matters as requested. During 2014 and 2015, telecommunications staff is conducting an analysis of the potential for broadband expansion.
Contact Carolee Hall, 334-0634 or Grace Seaman, 334-0352.

The **Consumer Assistance Section** includes five division investigators who resolve conflicts between utilities and their customers. Customers faced with service disconnections often seek help in negotiating payment arrangements. Consumer Assistance may mediate disputes over billing, deposits, line extensions and other service problems.

Consumer Assistance monitors Idaho utilities to verify they are complying with commission orders and regulations. Investigators participate in general rate and policy cases when rate design and customer service issues are brought before the commission.
Contact Beverly Barker, administrator for the Consumer Assistance section, at 334-0302.

Railroad and Pipeline Safety Section

The Rail Section oversees the safe operations of railroads that move freight in and through Idaho and enforces state and federal regulations safeguarding the transportation of hazardous materials by rail in Idaho. The commission's rail safety specialist inspects railroad crossings and rail clearances for safety and maintenance deficiencies. The Rail Section helps investigate all railroad-crossing accidents and makes recommendations for safety improvements to crossings.

As part of its regulatory authority, the commission evaluates the discontinuance and abandonment of railroad service in Idaho by conducting an independent evaluation of each case to determine whether the abandonment of a particular railroad line would adversely affect Idaho shippers and whether the line has any profit potential. Should the commission determine abandonment would be harmful to Idaho interests, it then represents the state before the federal Surface Transportation Board, which has authority to grant or deny line abandonments.
Contact Joe Leckie, rail section manager, at 334-0331.

Pipeline Safety

The pipeline safety section oversees the safe operation of the intrastate oil and natural gas pipelines in Idaho.

The commission's pipeline safety personnel verify compliance with state and federal regulations by on-site inspections of intrastate pipeline distribution systems. Part of the inspection process includes a review of record-keeping practices and compliance with design, construction, operation, maintenance and drug/alcohol abuse regulations.

Key objectives of the program are to monitor accidents and violations, to identify their contributing factors and to implement practices to avoid accidents. All reportable accidents will be investigated and appropriate reports filed with the U.S. Department of Transportation in a timely manner.
***Contact Joe Leckie, pipeline safety program manager, at 334-0331*.**

WHY CAN'T YOU JUST TELL THEM NO?

One of the most frequently asked questions the PUC receives after a utility files a rate increase application is, ***"Why can't you just tell them no?"*** Actually, we can, but not without evidence.

For nearly 100 years, public utility regulation has been based on this **regulatory compact** between utilities and regulators: *Regulated utilities agree to invest in the generation, transmission and distribution necessary to adequately and reliably serve all the customers in their assigned territories. In return for that promise to serve, utilities are guaranteed recovery of their prudently incurred expense along with an opportunity to earn a reasonable rate of return.* The rate of return allowed must be high enough to attract investors for the utility's capital-intensive generation, transmission and distribution projects, but not so high as to be unreasonable for customers.

In setting rates, the commission must consider the needs of **both** the utility and its customers. The commission serves the public interest, not the popular will. It is not in customers' best interest, nor is it in the interest of the State of Idaho, to have utilities that do not have the generation, transmission and distribution infrastructure to be able to provide safe, adequate and reliable electrical, natural gas and water service. This is a critical, even life-saving, service for Idaho's citizens and essential to the state's economic development and prosperity.

Unlike unregulated businesses, utilities cannot cut back on service as costs increase. As demand for electricity, natural gas and water grows, utilities are statutorily required to meet that demand. In Idaho recently, and across the nation, a continued increase in demand as well as a number of other factors have contributed to rate increases on a scale we have not witnessed before. It is not unusual now for Idaho's three major investor-owned electric utilities to file annual rate increase requests.

In light of these continued requests for rate increases, the Commission walks a fine line in balancing the needs of utilities to serve customers and customers' ability to pay.

When a rate case is filed, our staff of auditors, engineers and attorneys will take up to six months to examine the request. During that period, other parties, often representing customer groups, will "intervene" in the case for the purpose of conducting discovery, presenting evidence and cross-examining the company and other parties to the case. The Commission staff, which operates independently of the commission, will also file its own comments that result from its investigation of the company's request. The three-member Commission will also conduct technical and public hearings.

Once testimony from the company, commission staff and intervening parties is presented and testimony from hearings and written comments is taken, all of that information is included in the official record for the case. It is only from the evidence contained in this official record that the Commission can render a decision.

If the utility has met its burden of proof in demonstrating that the additional expense it incurred was 1) **necessary** to serve customers and 2) ***prudently incurred***, the commission must allow the utility to recover that expense. The commission can -- and often does -- deny recovery of some or all the expense utilities seek to recover from customers if the commission is confident it has the legal justification to do so. (See pages 18 and 19 of this report.) Utilities and parties to a rate case have the right to petition the Commission for reconsideration. If reconsideration is not granted, utilities or customer groups can appeal the Commission's decision to the state Supreme Court.

In the end, the Commission's job is to ensure that customers are paying a reasonable rate and are receiving adequate and reliable service and that utilities are allowed to recover their prudently incurred expenses and earn a fair rate of return.

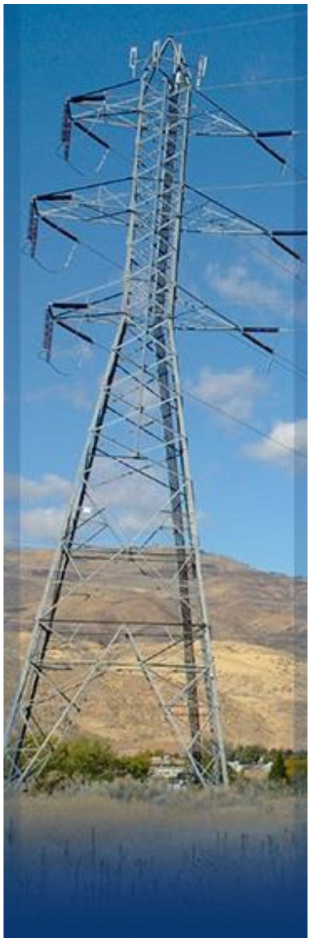
AVERAGE RESIDENTIAL RETAIL PRICES OF ELECTRICITY BY STATE 2013

The information below was provided by the Energy Information Administration, a division of the U.S. Department of Energy. It is an average of retail rates by state, including rates for investor-owned utilities as well as publicly-owned utilities, such as rural electric co-ops and municipalities. This data was released in 2015, but is an average of rates in 2013. Idaho's average rate ranks 50th of 50 States and the District of Columbia. Louisiana's average retail rate was the lowest in the nation during 2013.

Name	Average Retail Price (cents/kWh)	Net Summer Capacity (MW)	Net Generation (MWh)	Total Retail Sales (MWh)
Alabama	9.18	32,547	152,878,688	86,182,548
Alaska	16.30	2,119	6,946,419	6,416,411
Arizona	9.81	27,587	110,904,994	75,063,343
Arkansas	7.62	16,355	65,005,678	46,859,567
California	13.50	71,329	199,518,567	259,538,038
Colorado	9.39	14,947	52,556,701	53,685,297
Connecticut	15.50	9,060	36,117,544	29,492,338
Delaware	11.10	3,357	8,633,694	11,519,331
District of Columbia	11.90	10	71,787	11,258,845
Florida	10.40	59,139	221,096,136	220,674,333
Georgia	9.37	38,488	122,306,364	130,978,872
Hawaii	34.00	2,730	10,469,269	9,639,157
Idaho	6.92	4,911	15,499,089	23,711,859
Illinois	8.40	45,146	197,565,363	143,540,004
Indiana	8.29	26,837	114,695,729	105,173,425
Iowa	7.71	16,019	56,675,404	45,709,100
Kansas	9.33	14,093	44,424,691	40,293,476
Kentucky	7.26	21,089	89,949,689	89,048,490
Louisiana	6.90	25,548	103,407,706	84,730,743
Maine	11.80	4,491	14,428,596	11,561,059
Maryland	11.30	12,215	37,809,744	61,813,552
Massachusetts	13.80	14,321	36,198,121	55,313,324
Michigan	10.98	30,332	108,166,078	104,818,191
Minnesota	8.86	15,447	52,193,624	67,988,535
Mississippi	8.60	15,404	54,584,295	48,387,675
Missouri	8.53	22,004	91,804,321	82,435,359

Name	Average Retail Price (cents/kWh)	Net Summer Capacity (MW)	Net Generation (MWh)	Total Retail Sales (MWh)
Montana	8.25	6,317	27,804,784	13,863,383
Nebraska	8.37	8,273	34,217,293	30,827,939
Nevada	8.95	10,476	35,173,263	35,179,918
New Hampshire	14.20	4,323	19,264,435	10,870,261
New Jersey	13.70	18,924	65,263,408	75,052,914
New Mexico	8.83	8,373	36,635,909	23,178,568
New York	15.20	39,520	135,768,251	143,162,668
North Carolina	9.15	30,391	116,681,763	128,084,893
North Dakota	7.83	6,490	36,125,159	14,716,956
Ohio	9.12	32,854	129,745,731	152,456,864
Oklahoma	7.54	23,485	77,896,588	59,340,624
Oregon	8.21	15,544	60,932,715	46,688,856
Pennsylvania	9.91	45,406	223,419,715	144,709,727
Rhode Island	12.70	1,781	8,309,036	7,708,334
South Carolina	9.10	23,083	96,755,682	77,780,953
South Dakota	8.49	4,057	12,034,206	11,734,210
Tennessee	9.27	21,322	77,724,264	96,381,472
Texas	8.55	109,568	429,812,510	365,104,131
Utah	7.84	7,631	39,402,961	29,723,368
Vermont	14.20	1,235	6,569,670	5,510,764
Virginia	9.07	24,849	70,739,235	107,794,985
Washington	6.94	30,910	116,835,474	92,336,441
West Virginia	8.14	16,285	73,413,405	30,817,241
Wisconsin	10.30	18,031	63,742,910	68,820,090
Wyoming	7.19	8,380	49,588,606	16,971,354
U.S. Total	9.84	1,063,033	4,047,765,259	3,694,649,786

SOLAR ISSUES DOMINATE 2015



Idaho commission reduces contract length for some PURPA projects to two years

Case No. IPC-E-15-01, AVU-E-15-01, PAC-E-15-03

August 19, 2015 – The commission is granting a request by the state's three major electric utilities to reduce the length of negotiated PURPA contracts to two years.

The commission found the previous 20-year contract length resulted in utilities and, consequently, customers paying unreasonable costs for renewable generation.

The federal Public Utility Regulatory Policies Act (PURPA) requires utilities to buy from qualifying renewable facilities (QFs) at an "avoided cost rate," set by the commission. The avoided cost rate is to be equal to what the utility avoids by not having to generate the power itself or buy it from another source. Thus, customers are to be held harmless by the PURPA requirement that utilities purchase from QFs. However, the commission determined that long-term contracts unreasonably overestimate future avoided cost, resulting in higher costs to utilities and their ratepayers, contrary to PURPA's avoided-cost principle. One hundred percent of PURPA power supply costs are passed on to ratepayers.

Last February, Idaho Power Company asked the commission to reduce QF contract lengths in response to a flood of solar project applications that it said would force it to buy energy it did not need, drive up rates and threaten the utility's ability to reliably deliver energy. At the time, the commission had already approved 13 Idaho Power agreements with QF developers for 400 megawatts of solar energy***. (The contracts for four of those projects, totaling 141 MW were later terminated.)*** Idaho Power claims it has 1,326 MW of QF solar capacity actively seeking energy sales agreements. Idaho Power now has 1,297 MW of renewable energy (not counting hydro) on its system or under contract. That's 40% of its 2014 peak load of 3,184 MW and 120% of its total minimum load of 1,073 MW.

In response, the commission temporarily reduced contract lengths for negotiated PURPA contracts to five years while it investigated Idaho Power's petition. Later, PacifiCorp, operating as Rocky Mountain Power in eastern Idaho, joined the case, claiming to have projects seeking contracts totaling 275.5 MW in its Idaho territory. PacifiCorp has 189.6 MW of existing Idaho PURPA contracts – for a total of 465 MW of existing and proposed PURPA generation, enough power to supply 108 percent of PacifiCorp's average Idaho retail load.

Idaho Power argued that allowing developers to obtain fixed prices over the long term causes electric rates to increase. Idaho Power's average cost for

PURPA contracts – for a total of 465 MW of existing and proposed PURPA generation, enough power to supply 108 percent of PacifiCorp's average Idaho retail load.

Idaho Power argued that allowing developers to obtain fixed prices over the long term causes electric rates to increase. Idaho Power's average cost for PURPA generation since 2001 has always exceeded the regional market price. The average cost for PURPA purchases, according to Idaho Power, is $62.49 per megawatt-hour compared to coal ($22.79), gas ($33.57) and non-PURPA, off-system purchases ($50.64). PacifiCorp claims that over the next decade the energy it will buy from its 141 PURPA contracts in its six-state territory will cost customers an average price of $66.32 per MWh, significantly higher than the regional market price of $38.11 per MWh.

Renewable developers claim the reduction in contract length will end solar and wind development in Idaho. They argued that during 1996-2001 when contract length was five years, Idaho Power executed only one PURPA contract. The commission said it was not persuaded that setting negotiated contracts to two will years will result in a substantial decline of renewable resources. "The utilities all have ample amounts of PURPA on their systems and additional renewable generation is in the queue," it said, adding that 20-year published rate* contracts are still in place.

The commission said shorter contract lengths will benefit consumers because the rate paid developers "becomes a truer reflection of the actual costs avoided by the utility and allows QFs and ratepayers to benefit from normal fluctuations in the market." Utilities will still be required to purchase from qualifying renewable developers, but with a shorter contract length that "merely functions as a reset for calculation of the QFs avoided costs in order to maintain a more accurate reflection of the actual costs avoided by the utility over the long term."

Once a two-year contract is approved, the commission noted, the new QF then becomes part of the utility's resource stack and the contract is eligible for continuous renewal for as long as the developer chooses to continue selling power to the utility. Rocky Mountain Power, for example, states that limiting contract length does not mean the project will have only a two-year life. "Rocky Mountain Power will be required to purchase the power produced as long as PURPA requirements exist," Rocky Mountain stated in its testimony. Limiting contract length "simply means that the price Rocky Mountain Power and its customers will be required to pay to the QF will be subject to adjustment ... and be more closely aligned with Rocky Mountain Power's current avoided cost."

Further, the commission noted, PURPA is not the only means through which a utility can acquire renewable resources. Utilities have developed non-PURPA renewable resources such as Avista's agreement with Palouse Wind and Idaho Power's agreement with Elkhorn Wind.

Renewable developers claimed the utilities are overreacting to the flood of applications, asserting that many of the projects seeking contracts will not be developed because, in Idaho Power's case, as more projects are added to its queue, the avoided cost rate to be paid QFs declines. The utilities argued they must take each request for a contract seriously and that any added generation impacts the utility's power supply cost.

The change in the mandatory minimum contract length is "not intended to be punitive to QFs," the commission said. For several years, the commission has been adjusting terms and conditions of PURPA contracts "in order to establish avoided cost rates that are just and reasonable to electric consumers, in the public interest and not discriminatory against QFs."

Those opposing the change in contract length also argued that QFs should be treated similarly to utilities, which are able to build large generation sources with recovery for investment spread over as long as 30 to 50 years. However, the commission said, QFs differ from utility sources in several significant ways. For example, utilities cannot be compensated for energy produced from a generating facility without first establishing the need for that generation through the PUC's Certificate of Need process. That's different than PURPA, which requires utilities to buy QF power whether the power is needed or not. Second, a utility-authorized resource is typically subject to competitive bidding, cost scrutiny and oftentimes is able to fit into the utility's need for dispatch better than a mandatory QF. Third, the fuel component for utility plants is adjusted annually, but is fixed for the duration of fuel-based, long-term QF contracts. PURPA contracts are special, the commission said, because federal law compels utilities to buy power without arms-length bargaining and without regard to whether the utility needs the power.

The commission said it has a long history of encouraging PURPA projects and renewable energy development in Idaho. PURPA generation increased modestly in the first 25 years (1982-2007) to 200 MW. Since 2007, Idaho Power, in particular, has experienced a six-fold increase in PURPA generation to 1,161 MW. Its power supply expense, it claims, will have increased by 575% from 2004 to 2024. During the course of this case, the commission conducted two public hearings, a technical hearing and received more than 200 written comments from customers.

Those commenting in favor of shortened contracts included a number of companies that are large consumers of power. Those companies cited an interest in keeping power costs low and fair and ensuring reliable service. Several of the companies said utilities should not be required to buy electricity they do not need. A number of Idaho school districts and community colleges also supported the petitions, noting the importance of maintaining low operational costs and supporting a balanced approach to encouraging wind and solar power.

Those opposing the utilities' petition included the City of Ketchum, the League of Women Voters and environmental organizations. They cited the need to promote renewable energy and claimed shorter contracts would eliminate solar development in Idaho. The Renewable Northwest Coalition, among other parties, supported keeping 20-year contracts but adjusting the energy rate component of the contracts annually after 10 years. Commission staff argued in favor of reducing contract lengths to five years.

Parties to the case in addition to the three utilities and commission staff included the Idaho Conservation League/Sierra Club, Intermountain Energy Partners, Micron, JR Simplot Co., Snake River Alliance, Ag Power DCD/Ag Power Jerome, Amalgamated Sugar Co., Twin Falls Canal Company/Northside Canal Company/American Falls Reservoir District, Clearwater Paper Corp., Idaho Irrigation Pumpers Association and the Renewable Energy Coalition.

PUC says solar projects must identify owner or owners

Case No. IPC-E-15-18, Order No. 33383

Sept. 24, 2015 – The commission denied an Idaho Power Company petition to declare that solar projects proposed in the Wood River Valley are actually one, large project that has been divided into 10 smaller projects in order to qualify for more attractive contract terms.

The commission did not rule on Idaho Power's claim regarding the disaggregation of the projects, but denied Idaho Power's request because the project or projects do not identify an owner, which is a requirement under the Schedule 73 tariff that governs projects 100 kilowatts or smaller.

Site Based Energy claims the ten, 100-kilowatt projects are separate, each with a distinct limited liability corporation (LLC) and distinct owners. Idaho Power claims it is a large 1-megwatt project with the same developer, John Reuter of Site Based Energy, and that the project or projects are "all located at the same site, on the same contiguous property, and divided into ten sections." Site Based Energy claims the projects have common ownership only of interconnection equipment and are seeking economies of scale by purchasing and building together.

The project or projects are seeking sales agreements with Idaho Power under the provisions of the Public Utility Regulatory Policies Act or PURPA.

Intermittent projects (primarily wind and solar) larger than 100 kilowatts must negotiate with the purchasing utility for a rate, rather than receiving the commission's published rate. Further, published rate contracts are for 20 years, while negotiated contracts are for two years.

In an attempt to resolve the impasse, the commission asked Site Based Energy to provide additional information regarding the owners and copies of the articles or certificates for each LLC. Site Based provided letters from 10 individuals who wrote they "intend to proceed with the solar project using a Special Purpose Entity, LLC DBA," but qualified their intent with, "if the projects are approved by the PUC." Nine of the ten proposed owners further conditioned their intent with the condition "if all the approvals are completed and the economics work out."

"Site Based did not provide any evidence that these LLCs exist, nor that they existed at the time the applications were submitted," the commission said. Idaho statutes state an LLC is created when a certificate of organization is filed with the secretary of state.

The commission said Idaho Power could have rejected the applications outright because they did not comply with the requirements of Schedule 73, calling for identification of a project or projects' owner. Instead, the utility opted to file a petition seeking a disaggregation finding. "Having determined that Site Based Energy's applications do not satisfy Schedule 73, the commission need not reach the other complex issues presented by the parties," the commission said.

Parties agree to temporary solar integration costs until a second Idaho Power study is completed

Case No. IPC-E-14-18, Order No. 33227

Feb. 13, 2015 – The commission adopted a settlement that sets the rates solar developers will pay to have their projects integrated into Idaho Power Company's distribution and transmission system until a new solar integration study can be completed.

The integration charge applies only to larger solar developers and does not impact residential or small-commercial customers who have rooftop solar installations.

The parties agreeing to the settlement include Idaho Power, commission staff, the Sierra Club, the Idaho Conservation League and the Snake River Alliance.

Solar and wind generation that varies in its energy output depending on sun and wind conditions requires back-up generation to ensure system reliability. Utilities must provide operating reserves from baseload (non-intermittent) generation resources – such as a natural gas or hydro plant – that can be quickly ramped up or down to offset changes in generation from variable generation. Restricting the use of baseload resources to provide back-up for intermittent generation results in higher power supply costs that are eventually passed on to customers, Idaho Power claims.

To prevent customers from paying those costs, Idaho Power proposed a solar integration charge that would be discounted from the amount the utility pays to solar developers. The charge gradually increases as solar generation increases. Developers will pay about 40 cents per megawatt-hour when there is 100 megawatts or fewer of solar generation on Idaho Power's system. That cost increases to $1.50 per MWh when solar penetration is between 100 and 300 MW; $2.80 per MWh at a solar penetration of between 300 and 500 MW; and $4.40 per MWh at a solar penetration of between 500 and 700 MW. Those amounts are for contracts signed this year and would gradually change during the length of the sales agreement.

Because there was disagreement among the parties regarding the methodology Idaho Power used in its 2014 solar integration study, the parties agreed that Idaho Power will initiate a second study this year. A Technical Review Committee will be used in that study that consists of staff from the Idaho and Oregon public utility commissions, Idaho Power personnel and technical experts from the parties to the settlement.

The settlement also outlines the issues a second study will consider. In the last three months, the commission has approved power purchase agreements between Idaho Power and developers of 13 solar projects totaling 400 megawatts. Integration charges have already been included in those contracts. Idaho Power also buys the output from 60 MW of solar projects in its Oregon territory.

The commission recently reduced the length of solar contracts from 20 years to five years while it processes an Idaho Power application to reduce the length of those contracts even further to two years. Idaho Power claims there are about another 885 MW of solar projects seeking contracts under federal PURPA provisions with the company.

Commission approves Idaho Power agreements with five solar projects

Case Nos. IPC-E-14-32, -33, -34;-35; and -36

Dec. 29, 2014 – The Commission approved Idaho Power Company sales agreements with five solar projects owned by Boston-based First Wind. The contracts, totaling about $322.5 million over 20 years, are for a total 100 megawatts, 20 MWs for each project.

The commission has yet to rule on another six solar projects totaling about 181 MW. Last month, the commission approved applications from two other solar projects, Boise City Solar and Grand View Solar II, totaling 120 MW. Idaho Power also recently signed six contracts for 60 MW of solar generation in Oregon.

While stating that the projects qualify under federal PURPA provisions, the commission's order expresses concern that the federal law may be compelling utilities to buy energy they do not need. The order states that utilities should inform the commission as to whether additional review of contract terms and conditions for federal PURPA projects is necessary.

PURPA requires regulated utilities to buy energy from independent, renewable generation projects at rates established by state commissions. The rate to be paid small-power producers is called an "avoided-cost rate," because it is based on the cost the utility avoids by not having to generate the energy itself or buy it from another source. The commission must ensure the avoided-cost rate is reasonable for utility customers because 100 percent of the price utilities pay to qualifying small-power producers is included in customer rates.

Congress enacted PURPA in response to a national energy crisis in the late 1970s with a goal to lessen the nation's dependence on foreign oil. "Unfortunately, PURPA does not address and FERC (Federal Energy Regulatory Commission) regulations do not adequately provide for consideration of whether the utility being forced to purchase QF power is actually in need of such energy," the commission said. Idaho Power's 20-year Integrated Resource Plan does not indicate the utility is in need of more energy sources. "And yet, in less than four months time, 13 QFs have contracted with Idaho Power for nearly 400 MW of solar generation – all expected to be on-line and producing power by the end of 2016," the commission said.

The commission reiterated that the combined potential contractual obligation of $1.4 billion for what could be 13 projects is passed on to ratepayers. While the projects will displace the fuel costs of Idaho Power's existing resources, "the capital costs of the displaced resources (such as baseload natural gas, coal and hydroelectric plants) will continue to be recovered through ratepayers' bills along with the costs of QF power." Because solar and wind generation is intermittent, other resources are sometimes needed to balance their variability as well as provide back-up generation.

The First Wind projects include American Falls Solar and American Falls Solar II in Power County, Murphy Flat Power in Owyhee County, Simco Solar in Elmore County and Orchard Ranch Solar in Ada County.

The developers will be paid a non-levelized avoided-cost rate over the 20-year term of the agreements, which means payments increase over the course of the agreement and vary according to light-load and heavy-load hours of the day and seasons of the year. The average levelized rate for the First Wind projects is about $63 per megawatt-hour and the value of the five 20-year contracts ranges from $60.2 million to $68 million. (See attached chart.)

Included in each contract is an integration charge the developer pays Idaho Power to cover the cost of integrating the energy into Idaho Power's transmission and distribution system. The integration cost increases as the amount of solar generation on Idaho Power's system increases. For these contracts, the charge ranges from $2.46 per MWh to $5.05 per MWh.

The agreements allow for a 2 percent deviation in estimated energy output before the price can be adjusted. A consistent deviation from the hourly energy generation estimates would be considered a material breach of the agreements. Also included is a "90/110" firmness requirement. If a project's generation exceeds 110 percent of estimated output, the developer is paid 85 percent of a market-based price for the generation above 110 percent of forecasted output. If the developer does not produce at least 90 percent of forecasted generation, then all output is paid at 85 percent of the market price.

Revenue from the sales of Renewable Energy Certificates associated with the projects will be split 50-50 between the developer and Idaho Power.

PUC approves six more solar projects

BOISE Jan. 8, 2015 – Sales agreements between the developer of six solar projects and Idaho Power Company have been approved, adding another 181 megawatts to the utility's rapidly growing portfolio of solar generation.

Since November, the Idaho Public Utilities Commission has approved Idaho Power agreements for 13 solar projects, totaling 400 MW and valued at $1.4 billion. Idaho Power also recently signed contracts for 60 MW of solar generation in its Oregon territory. ***(Four of these projects, totaling 141 MW, were eventually terminated.)***

The projects approved this week are owned by Ketchum-based Intermountain Energy Partners. Mark van Gulik is the developer. Five of the projects are in Elmore County and one is in Power County.

In its order approving the agreements, the commission repeated the same concern it did a month ago that the federal government's must-buy provisions for qualifying renewable energy projects may be compelling utilities to buy energy they do not need.

The federal Public Utility Regulatory Policies Act of 1978 (PURPA) requires regulated utilities to buy energy from independent, renewable generation projects at rates established by state commissions. The rate to be paid small-power producers is called an "avoided-cost rate," because it is based on the cost the utility avoids by not having to generate the energy itself or buy it from another source. The commission must ensure the avoided-cost rate is reasonable for utility customers because the price utilities pay to qualifying small-power producers is included in customer rates.

The commission recently concluded a major review of PURPA contract terms and conditions and updated how it calculates avoided-cost rates. Developers continue to request contracts with Idaho Power in significant enough numbers "that we remain concerned about the company's ability to balance the substantial amount of must-take intermittent generation and still reliably serve customers," the commission said. The order says utilities should inform the commission as to whether additional review of PURPA contract terms and conditions is necessary.

Congress enacted PURPA in response to a national energy crisis in the late 1970s with a goal to lessen the nation's dependence on foreign oil. "Unfortunately, PURPA does not address and FERC (Federal Energy Regulatory Commission) regulations do not adequately provide for consideration of whether the utility being forced to purchase QF power is actually in need of such energy," the commission said.

Idaho Power's 20-year Integrated Resource Plan does not indicate the utility is in need of more energy sources. "And yet, in less than four months time, 13 QFs have contracted with Idaho Power for nearly 400 MW of solar generation – all expected to be on-line and producing power by the end of 2016," the commission said.
The developer will be paid a non-levelized avoided-cost rate over the 20-year term of the agreements, which means payments increase over the course of the agreement and vary according to light-load and heavy-load hours of the day and seasons of the year. The average levelized rate for these projects is about $61 per megawatt-hour and the values of the six 20-year contracts range from $67.8 million to $243.8 million.

Included in each contract is an integration charge the developer pays Idaho Power to cover the cost of integrating the energy into Idaho Power's transmission and distribution system. The integration cost increases as the amount of solar generation on Idaho Power's system increases. For these contracts, the charge ranges from $2.01 per MWh to $4.60 per MWh in the first year of the contract and escalates through the end of the 20-year term in 2036.

The agreements allow for a 2 percent deviation in estimated energy output before the price can be adjusted. A consistent deviation from the hourly energy generation estimates would be considered a material breach of the agreements. Also included is a "90/110" firmness requirement. If a project's generation exceeds 110 percent of estimated output, the developer is paid 85 percent of a market-based price for the generation above 110 percent of forecasted output. If the developer does not produce at least 90 percent of forecasted generation, then all output is paid at 85 percent of the market price.
Revenue from the sales of Renewable Energy Certificates associated with the projects will be split 50-50 between the developer and Idaho Power.

OTHER MAJOR ISSUES: TRANSMISSION SWAP, SECOND AREA CODE

PUC approves swap of transmission assets between Idaho Power, PacifiCorp

Case No. IPC-E-14-41, Case No. PAC-E-14-11, Order No. 33313

June 10, 2015 – The commission approved a $43 million transmission asset swap between Idaho Power Company and PacifiCorp, which does business in eastern Idaho as Rocky Mountain Power.

In its order approving the transaction, the Idaho Public Utilities Commission said the swap, which will replace outdated sharing agreements between the utilities, will better serve the utilities and their transmission and retail customers.

Under the swap, Idaho Power and PacifiCorp will re-allocate ownership in each of three 345-kilovolt transmission lines that transmit generation from Wyoming's Jim Bridger coal-fired power plant to Idaho Power customers across southern Idaho and to PacifiCorp customers in Oregon, Washington and California. The swap would allocate to PacifiCorp two-thirds ownership in each line and Idaho Power one-third ownership. Currently, PacifiCorp owns two of the three 345-kV lines and Idaho Power owns one. In addition, PacifiCorp would obtain full ownership of two 230-kV lines and substation that connect the Bridger plant to Point of Rocks and Rock Springs, Wyoming.

Because the transaction involves interstate transmission, it must also be approved by the Federal Energy Regulatory Commission (FERC).

Idaho state statute requires that whenever a regulated utility buys or sells major generation or transmission assets, the commission must find that the transaction is in the public interest, that costs and rates of existing service are not increased as a result of the transaction and that new owners have the bona fide intent and financial ability to operate and maintain the transferred assets.

The commission determined the asset swap meets all those conditions. Further, the commission said, the increased operational flexibility resulting from the transaction will ensure more efficient management of transmission system upgrades, facilitate expected load growth, and, ultimately, improve reliability for customers.

Under the swap, PacifiCorp would be provided about 1,600 megawatts across Idaho Power's system to move energy from the Bridger plant to its Western service territory in Washington, Oregon and California. About 510 MW of that 1,600 MW would be firm transmission service that PacifiCorp will purchase under Idaho Power's Open Access Transmission Tariff. *(The OATT is a tariff or rate that a utility or any transmission provider can charge those seeking available capacity. To encourage a competitive wholesale electric market, the OATT must be approved by FERC as cost-based and non-discriminatory to those who seeking access.)*

Because the transaction is expected to result in greater transmission revenue to Idaho Power from PacifiCorp and other transmission customers, the commission directed Idaho Power to establish a deferred account for those revenues and annually report the amounts for possible later sharing with customers. PacifiCorp is also expected to pay reduced transmission wheeling expense, which will also be tracked and reported for possible later benefit to customers. The Industrial Customers of Idaho Power urged the commission to wait until after the FERC proceeding resolved. The commission said the conditions of the Idaho statute are met regardless of what FERC may decide. ICIP also said transmission upgrades by Idaho Power resulting from the transaction may increase Idaho Power's retail rates. The commission said transmission upgrades are reviewed for prudency in future rate cases.

Up until this agreement, Idaho Power and PacifiCorp operated under a series of "Legacy Agreements" -- dating to as far back as 1969 -- regarding the construction, ownership and operation of the Bridger coal plant and its associated transmission lines. The agreements were drafted before the advent of FERC's open-access policies, which allow access to the transmission grid for more transmission providers on a non-discriminatory basis. The Legacy Agreements are outdated, inefficient and don't recognize the changing load characteristics of each utility, Idaho Power and PacifiCorp said.

Currently, 1400 MW of PacifiCorp's east-to-west transfer rights are tied only to generation from the Bridger plant. Under the new agreement, PacifiCorp would be able to make east-to-west transfers without restriction on the source of energy, using a combination of transmission service rights over Idaho Power's system and its own newly owned assets. Further, Idaho Power's ownership of the Three Mile Knoll to Goshen line south of Idaho Falls limits PacifiCorp's ability to reliably and cost-effectively respond to Goshen area customer load requirements during certain outage scenarios.

PacifiCorp would also have access to 400 MW of "dynamic service," a 200 MW increase. Dynamic transfers are firm energy transfers that can be scheduled using a shortened time frame (within the hour) and for intervals as briefly as four seconds. Dynamic transfers produce benefits for participants by more effectively stabilizing electric load within the hour, increasing the pool of available energy services and reducing the cost of integrating renewable energy into energy delivery.

Idaho Power would be provided capacity on various portions of PacifiCorp's transmission system.

Further, Idaho Power claims the OATT paid it by PacifiCorp would more accurately reflect Idaho Power's cost of service, benefitting Idaho Power's retail customers. Idaho Power claims that the transaction will reduce its revenue requirement by $56 million over the next 10 years, due primarily to higher transmission revenues it will get from transmission customers. Those revenues serve as a credit to retail customer rates.

Idaho's second area code – 986 – launches in late 2017

Case No. GNR-T-15-06, Order No. 33414

Nov. 2, 2015 – The commission approved a 16-month plan for Idaho's second area code to be implemented in late 2017. An hour after the Idaho Public Utilities Commission issued its order approving the plan, the agency that contracts with the federal government to administer the nation's area code numbering plan, Neustar, issued Idaho's second area code: **986.**

The second area code will be issued only to new telephone numbers beginning in late 2017. Idaho is one of few states that still has one area code, "208" issued in 1947.

The commission adopted the unanimous recommendation of Idaho's telecommunications providers and commission staff that the state implement an *"all services overlay,"* which assigns the new area code statewide to new numbers. This option will ultimately require that all customers in Idaho dial 10 digits (area code, plus prefix, plus four-digit number) beginning in late 2017.

A second option was to implement a *"geographic split,"* which would have assigned the new area code to all numbers in one-half the state, requiring all customers assigned the new code to change their telephone numbers. This option would have retained seven-digit dialing for calls within the same area code. About 27 of 41 written comments the commission received favored the split option, but none of the comments addressed future trends that will eventually end seven-digit dialing.

"Neither option is ideal," the commission said, but the overlay will not cause the same level of disruption and expense as a geographic split would have forced on the half of the state required to change its numbers. Furthermore, the commission said, developing technology "will eventually drive seven-digit dialing into obsolescence in the future." Implementation of a geographic split may serve only to prolong seven-digit dialing for a short period, the commission said. "Thus, any future dialing change and relief planning will be eased by the implementation of 10-digit dialing now rather than later." Under the split, the commission said, businesses of all sizes would have experienced significant disruptions. "Any goodwill of business identification associated with existing phone numbers" would have been lost, the commission said, as businesses would be required to change advertising, letterhead, web pages and business cards. "This is no small expense nor a minor nuisance," the commission said.

A commission staff investigation determined that every area code addition for the last eight years has been a geographic overlay, rather than a split. In 2008, the West Virginia Public Service Commission reversed its original decision when it found the geographic split created too much of an economic burden and that current technology generally "alleviates most of the problems (associated) with 10-digit dialing." Commission staff noted that most telecommunications devices, even landline phones, have number storage capability that allows customers to dial entire numbers with the press of one or two buttons.

Neustar has been informing the state that a second area code will be needed since its original forecasted exhaust date of August 2001. In response, the commission implemented various numbers conservation plans that have been successful in delaying a second area code by at least 15 years. However, the proliferation of wireless telephones, new competitive telephone companies, paging and messaging services and Voice over Internet Protocol (VoIP) is contributing to the increase in demand for new numbers, making further delay impossible.

The plan adopted by the commission initiates a 16-month transition and customer education process. Telecommunications providers will begin customer education in about six months and commission staff will conduct customer education workshops throughout the state beginning in spring of next year. A "permissive 7-digit and 10-digit dialing period," will begin at about the end of 2016. This nine-month period will allow customers to begin 10-digit dialing even though seven-digit dialing will still work. Then, in the fourth quarter of 2017, mandatory 10-digit dialing begins.