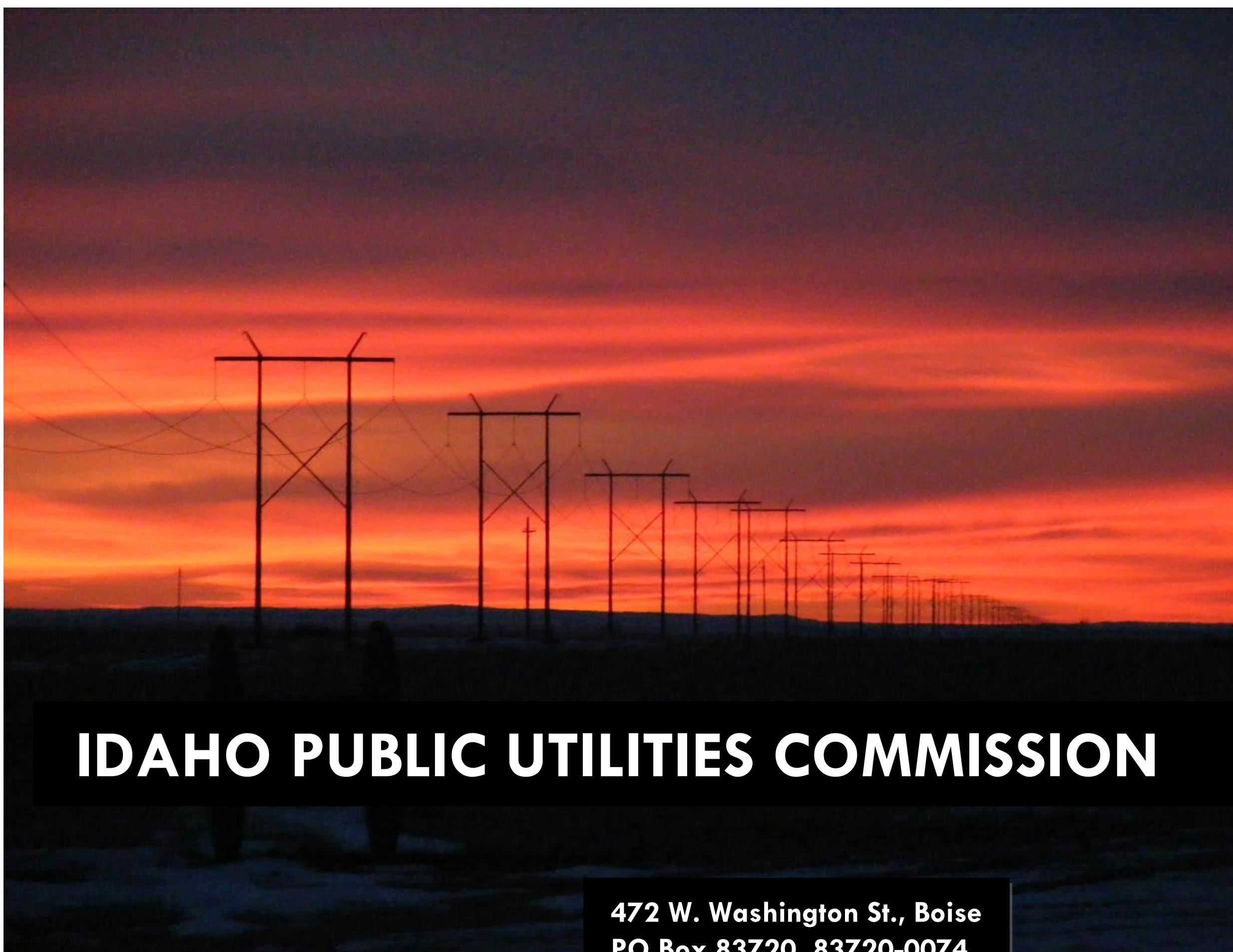

IDAHO PUBLIC UTILITIES COMMISSION

2016

472 W. Washington St., Boise
PO Box 83720 83720-0074
208.334.0300

www.puc.idaho.gov

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Idaho Public Utilities Commission

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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 2016 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, 2016

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 2016 Annual Report. This report is a detailed description of the most significant cases, decisions and other activities during 2016. The financial report on Page 10 is a summary of the commission's budget through the conclusion of Fiscal Year 2016, which ended June 30, 2016.

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

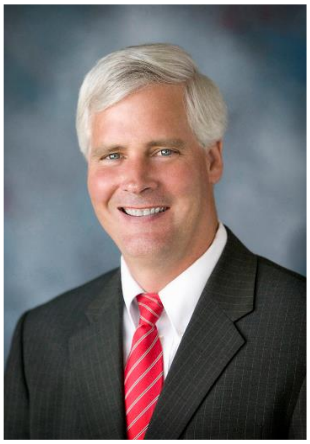
Sincerely,

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.

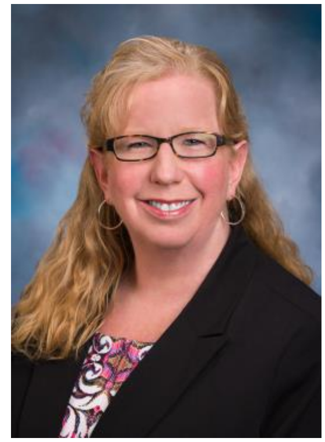
Kjellander, a Republican, was elected to three terms (1994-1999) in the Idaho House of Representatives, where he served as a member of the House State Affairs, Judiciary and Rules, Ways and Means, Local Government and Transportation committees. During his last term in office, Kjellander was elected House 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 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 FCC's 706 Joint Board and serves as vice chairman of the NARUC Telecommunications Committee. He is currently serving as a NARUC representative to the North American Numbering Council (NANC) and an at-large member of the National Council on Electricity Policy (NCEP).

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

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, Raper served seven years as a deputy attorney general assigned to the Public Utilities Commission. In her time as an attorney for the PUC, Raper was involved in electric, gas, water and telecommunications cases. Commissioner Raper defended the Idaho PUC’s decisions regarding PURPA in front of the Idaho Supreme Court, District Court and Federal Energy Regulatory Commission.

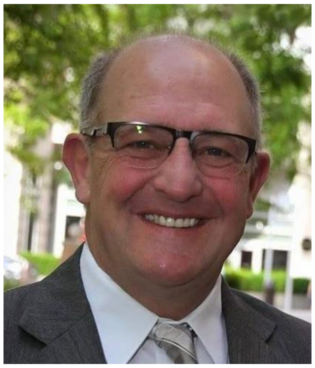
Prior to her work in the Attorney General’s office, she served for eight years as a law clerk to Commissioner R.D. Maynard on the Idaho Industrial Commission. Raper developed expertise in Idaho workers’ compensation law matters appealed through the state Department of Labor.

Commissioner Raper serves on the Electricity Committee of the National Association of Regulatory Utility Commissioners (NARUC) and is the incoming vice president of the Western Conference of Public Service Commissioners. She also currently serves on the Member Advisory Committee of the Western Electric Coordinating Council (WECC) and as a member of the State Provincial Steering Committee.

Commissioner Raper was born in Delaware and moved to Utah with her family in the early 1980s. 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.

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

ERIC ANDERSON



Eric Anderson of Priest Lake was appointed to the commission in December 2015. Commissioner Anderson's term expires in January 2019.

Anderson, a Republican, served 10 years in the Idaho Legislature from 2005-14. He chaired the House Ways and Means Committee during his final term. He also served on these committees: Environment, Energy and Technology; Resources and Conservation; and State Affairs. He chaired a legislative Interim Subcommittee on Renewable Energy.

He received his Bachelor of Arts degree in political science and government from Eastern Washington University in 1979.

A general contractor and real estate broker, he also served as director and vice president of Sandpoint-based Northern Lights Inc. He's also served as a director on the Idaho Consumer Owned Utilities Association, the National Rural Electric Cooperative Association and the Idaho Energy Resources Authority. He is a past member and more recently an advisor to the Pacific States Marine Fisheries Council and the Pacific Northwest Economic Region's Executive Council.

FINANCIAL SUMMARY FUND 0229

Fiscal Years 2012 – 2016

Description	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016
Personnel Costs	$3,304,100	$3,491,500	$3,528,900	$3,563,500	$3,835,900
Communication Costs	$29,500	$31,300	$31,000	$23,500	$28,700
Employee Development Costs	$62,500	$55,600	$53,200	$99,200	$98,700
Professional Services	$9,800	$9,700	$12,300	$8,500	$18,600
Legal Fees	$525,300	$551,600	$519,700	$538,400	$579,400
Employee Travel Costs	$115,400	$123,600	$141,100	$152,500	$159,200
Fuel & Lubricants	$4,100	$4,700	$2,700	$5,600	$2,900
Insurance	$1,000	$3,100	$4,400	$4,300	$2,000
Rentals & Leases	$294,200	$276,100	$584,600	$308,600	$223,800
Misc. Expenditures	$85,600	$117,000	$104,700	$84,400	$83,900
Computer Equipment	$24,300	$29,200	$66,400	$73,600	$52,200
Office Equipment	$0	$13,000	$11,900	$16,500	$8,100
Motorized/Non-Motorized Equip	$52,300	$0	$0	$32,500	$0
Specific Use Equipment	$0	$0	$0	$0	$1700
Total Expenditures	**$4,508,100**	**$4,706,400**	**$5,060,900**	**$4,911,100**	**$5,095,100**
Fund 0229-20 Appropriation	**$4,768,200**	**$4,916,800**	**$5,061,700**	**$5,595,600**	**$5,766,500**
Unexpended Balance	**$260,100**	**$210,400**	**$800**	**$684,500**	**$671,400**

COMMISSION STRUCTURE AND OPERATIONS

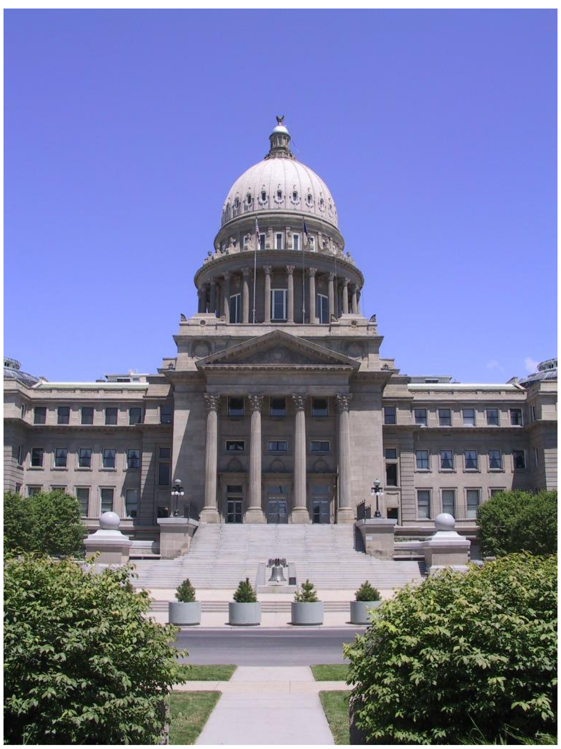
Under state law, the Idaho Public Utilities Commission supervises and regulates Idaho's investor-owned utilities – electric, gas, telecommunications and water – assuring adequate service and affixing just, reasonable and sufficient rates.

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.

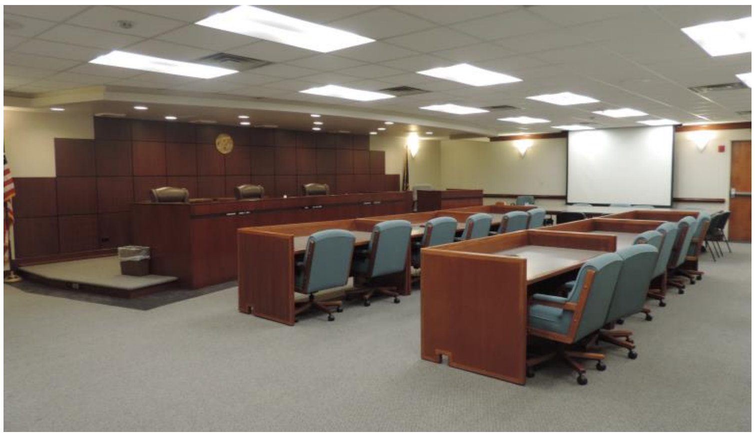
In its quasi-legislative capacity, the commission sets rates and makes rules governing utility operations. In its quasi-judicial mode, the commission hears and decides complaints, issues written orders that are similar to court orders and may have its decisions appealed to the Idaho Supreme Court. In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

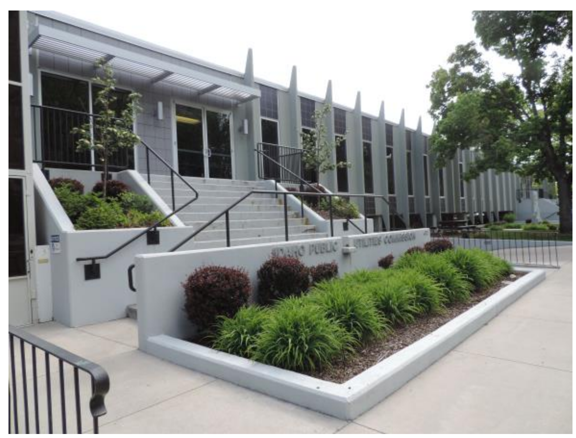


PUC hearing room

There are **technical hearings** and **public hearings**. At technical hearings, formal parties who have been granted "intervenor status" present 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.

Many public hearings are conducted in cities and towns that are part of the service territory of the utility seeking a rate increase. In less contested rate cases, the commission will sometimes conduct hearings telephonically 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 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.



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

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 Meetings Law, commissioners may also privately deliberate fully submitted matters.

Commission Staff

OUR MISSION

- ***Determine fair, just and reasonable rates and utility practices for electric, gas 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 is the primary contact for matters concerning Information Technology, Fiscal and Human Resources. He also serves as a liaison between the commission and other state agencies and the Legislature. ***Contact IT, Fiscal, Human Resources. 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 Karl Klein, legal division director, at 334-0320.***

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 six auditors and one manager 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, two analysts and one supervisor 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 Mike Louis, engineering section supervisor, at 334-0316.***

The **Technical Analysis Section** of four utility analysts and one supervisor 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. ***Contact Carolee Hall, 334-0364 or Grace Seaman, 334-0352.***

The **Consumer Assistance Section** includes five division investigators and one supervisor 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, Consumer Assistance administrator, at 334-0302.

Railroad Section

Our rail inspector 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 four-member 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 more than 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.

The commission walks a fine line in balancing the needs of utilities to serve customers and customers' ability to pay.

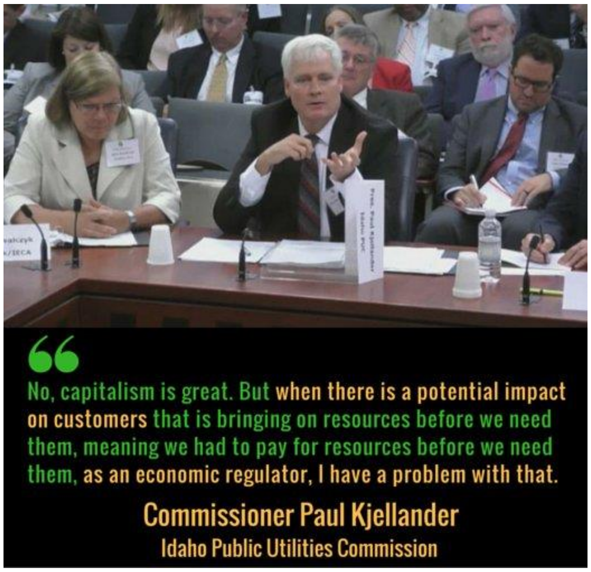
When a rate case is filed, our staff of auditors, engineers and attorneys will take up to six months to examine the request. During that period, other parties, often representing customer groups, will "intervene" in the case for the purpose of conducting discovery, presenting evidence and cross-examining 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.

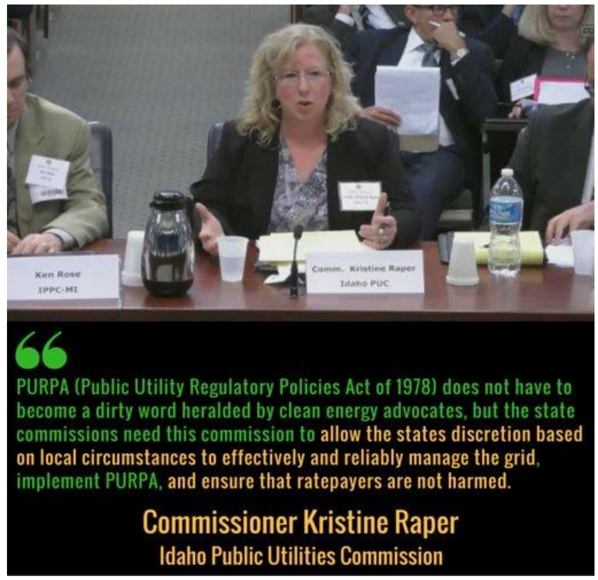
Once testimony from the company, commission staff and intervening parties is presented and testimony from hearings and written comments is taken, all of that information is included in the official record for the case. It is only from the evidence contained in this official record that the Commission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

2016 MAJOR EVENTS

Idaho commissioners part of FERC technical conference





Idaho Commission President Paul Kjellander and Commissioner Kristine Raper testified at a Federal Energy Regulatory Commission technical hearing on June 29, 2016, regarding FERC's implementation of PURPA. Kjellander and Raper and Montana Commissioner Travis Kavulla (testifying as president of the National Association of Regulatory Utility Commissioners) were the only state regulators among the 20 panelists who testified at the day-long hearing.

PURPA is the Public Utility Regulatory Policies Act. Enacted in 1978 during the energy crisis to incent renewable generation, PURPA requires that electric utilities buy power produced from qualifying independent small-power producers. The rate to be paid small-power producers is determined by state commissions and is called an "avoided-cost rate" because it is to be equal to the cost the electric utility avoids if it would have had to generate the power itself or purchase it from another source. In Idaho, 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.

Over the last decade, Idaho has been a focal point in the national debate over how states manage a rapid increase in the number of new PURPA projects that are intermittent in their generation, particularly wind and solar projects. After the Idaho commission reduced the size of projects that can qualify for the state's published rates and stopped the practice of project disaggregation (under which the same developer broke up a large project into several smaller projects and spaced them a mile apart, the minimum required by FERC to be considered a separate project), wind developers filed complaints at FERC. In response, FERC filed a complaint in federal court in March 2013 asking the court to find that the Idaho commission had violated PURPA and enjoin the PUC from imposing conditions on sales agreements between Idaho Power Company and the developers of several wind projects. It was the first time FERC had taken a state to court over a PURPA-related action. Some of the same wind developers also appealed to the state Supreme Court.

On Dec. 18, 2013, the state Supreme Court unanimously affirmed the PUC's decision to deny approval of the Grouse Creek wind contracts. Six days later, FERC and the Idaho commission signed a Memorandum of Agreement under which FERC dismissed its court claims and the PUC dismissed any counterclaims.

Some of the same issues resurfaced two years later with the rapid development of new solar PURPA projects. In the three months from November 2015 to January 2015, the Idaho PUC approved 13 solar projects totaling 400 MW, some of which were later canceled.

While supportive of the overall goals of PURPA to incent renewable generation, the Idaho commission has expressed growing concern over rates customers must pay for PURPA projects and whether those projects are needed by the utility.

Idaho's three investor-owned utilities have about 135 PURPA projects under contract representing a nameplate capacity of more than 1,200 megawatts. In the first 25 years of PURPA, Idaho Power had accumulated less than 200 MW of PURPA generation and PacifiCorp had about 300 MW in eastern Idaho. Since 2007, the amount of PURPA generation for Idaho Power increased nearly six-fold and seven-fold for PacifiCorp.

This rapid development of new projects came at the same time utilities were experiencing flat or slight growth in energy consumption. The rapid development of PURPA projects prompted a number of concerns from the Idaho commission including, 1) PURPA generation that is not needed to serve loads, 2) large amounts of intermittent generation requiring stand-by generation, 3) long-term, fixed-price PURPA contracts that place greater risks on both the utilities and customers, 4) operating and reliability issues, and 5) planning issues caused by the "must purchase" obligations of PURPA, resulting in the procurement of large amounts of unneeded power.

The FERC technical conference focused on two issues: the "mandatory purchase obligation," that utilities have under PURPA and the determination of avoided costs. Participants were asked to submit post-technical conference comments. Below (pages 19-32) are the comments the Idaho commission submitted to FERC in early November 2016.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

TECHNICAL CONFERENCE ON IMPLEMENTATION ISSUES UNDER THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978	)))))	**DOCKET NO. AD16-16-000**

POST-TECHNICAL CONFERENCE COMMENTS OF THE IDAHO PUBLIC UTILITIES COMMISSION

The Idaho Public Utilities Commission (Idaho PUC) again thanks the Commission for the opportunity—through written comments and as panelists at the technical conference—to offer our perspective on issues concerning implementation of the Public Utility Regulatory Policies Act of 1978. The Idaho PUC is the state agency that regulates public utilities operating in Idaho. Our responsibilities include ensuring the reliability of electric service in Idaho at just and reasonable rates, and implementing PURPA in accordance with the Commission's regulations. We now submit the following post-technical conference comments in response to the Commission's September 6, 2016 notice inviting comments on specific issues enumerated below.

A. <u>The One-Mile Rule and Project Manipulation through Disaggregation</u>

The "one-mile rule" refers to the Commission's test for determining whether facilities are located at the same site for purposes of eligibility under PURPA. Under PURPA Section 201, the maximum size of a small power production facility seeking Qualifying Facility status is 80 megawatts (MW) "together with any other facilities located at the same site (as determined by the Commission)." The Commission's regulations—originally adopted in Order No. 70[1]—provide in relevant part:

> § 292.204 Criteria for qualifying small power production facilities.
>
> (a) *Size of the facility –*
>
> (1) *Maximum size.* Except as provided in paragraph (a)(4) of this section [which addresses certain QFs certified before 12/31/1994], the power production capacity of a facility for which qualification is sought, together with the power production capacity of any other small power production facilities that use the same energy resource, are owned by the same person(s) or its affiliates, and are located at the same site, may not exceed 80 megawatts.

[1] Order No. 70, FERC Stats. & Regs. ¶ 30,134, at 30,943-44, *order on reh'g*, Order Nos. 69-A and 70-A, FERC Stats. & Regs. ¶ 30,160 (1980), *aff'd in part and vacated in part*, *American Elec. Pwr. Svc. Corp. v. FERC*, 675 F.2d 1226 (D.C. Cir. 1982), *rev'd in part*, *American Paper Inst., Inc. v. American Elec. Pwr. Svc. Corp.*, 461 U.S. 402 (1983).

(2) *Method of calculation.*

(i) For purposes of this paragraph, facilities are considered to be located at the same site as the facility for which qualification is sought if they are located within one mile of the facility for which qualification is sought and, for hydroelectric facilities, if they use water from the same impoundment for power generation.

(ii) For purposes of making the determination in clause (i), the distance between facilities shall be measured from the electrical generating equipment of a facility.

18 C.F.R. § 292.204(a)(1) and (2).

To determine whether a facility is within the 80 MW limit, the facility's capacity is combined with the capacity of any other facilities which use the same energy resource, are owned by the same person(s) or its affiliates, and are located at the same site. 18 C.F.R. § 292.204(a)(1). Facilities are presumed to be at the same site as a facility for which qualification is sought if they are within one mile of that facility (measured from electrical generating equipment). *Id.* at § 292.204(a)(2). This is referred to as the "one-mile rule."

Applying this rule, if two facilities share the same energy resource, are owned by the same person, and are located within one mile of each other, their capacities are aggregated for purposes of determining whether they are under the 80 MW limit. On the other hand, if two facilities share the same energy resource, are owned by the same person, but are located one mile and 10 feet from each other, they are considered two separate facilities and their capacities will not be aggregated. The Commission asked for comments on three specific questions about the rule. The Idaho PUC's comments are as follows.

1. Should the presumption inherent in the one-mile rule be made rebuttable? If so, who—the interconnecting utility or the QF—should bear the burden of overcoming the presumption?

The Commission has stated that:

> . . . [S]ection 292.204(a)(2)(i) of the Commission's regulations was not intended to establish and did not establish merely a rebuttable presumption. Instead, section 292.204(a)(2)(i) established a rule that facilities that use the same energy resource, and that are owned by the same person(s) or its affiliates and that are located within one mile of each other are at the same site. There is certainly no language in that rule that suggests otherwise, i.e., that it is merely a rebuttable presumption. To the contrary, the language reads, as it was supposed to read, as a rule.[2]

Recognizing both that the one-mile rule in its current form is not rebuttable and that "when we hear about costs totaling potentially in the billion dollars or more over relatively sparsely populated

[2] *North Laramie Range Alliance*, 139 FERC ¶ 61,190 at P 22 (2012).

states, it's a big enough deal . . . to get our attention,"[3] we respectfully suggest that the administrative considerations that originally led the Commission to adopt a hard-and-fast rule may be worth revisiting.[4] The one-mile rule's current prescription that facilities within a mile of each other are located at the same site (and conversely, that those that are more than a mile apart are not at the same site) should be rebuttable by the facility/project developer. The burden of overcoming the presumption must be on the project developer because only the project developer—not the utility—has the information that would be necessary to meet or rebut the presumption. Under the rule, a facility that is within one mile of others with which it has a common owner and shares an energy resource will be presumed to be a single QF together with those other facilities. To qualify for PURPA, the aggregate sum of their capacity has to be within 80 MW.

If the facility wishes to challenge this presumption, it is the party that has the information to rebut it and should bear the burden of doing so. Conversely, a facility that is located at the same site as others and shares an energy resource, but has different ownership, will be presumed to be a separate QF. If a utility or a state regulator believes the facilities really do share common ownership, or that a single facility has been segmented or disaggregated artificially in order to gain the advantage of PURPA's must-purchase obligation, it might refuse to offer or to approve (as the case may be) separate contracts to the facilities. In that case, the project developer can bring a complaint to the state regulatory agency. If the utility presents evidence that the facilities share ownership, the project developer has the information to prove otherwise and should bear the burden of demonstrating that they do not.

In his earlier written comments in this docket, Commissioner Kjellander proposed several criteria that could be used to determine whether certain QF facilities are located at the same site. These factors could be used by the QF, or by utilities, to challenge the presumption. The proposed parameters are reproduced here for ease of reference and would allow for a detailed, fact-based analysis. The parameters include, but are not intended to be limited to, whether facilities that are in close proximity:

- Use the same motive force or fuel source
- Are owned or controlled by the same person(s) or affiliated person(s)
- Are placed in service within 12 months of an affiliated project's commercial operation dates as specified in the power sales agreement
- Share a common point of interconnection or interconnection facilities
- Share common control, communications, and operation facilities
- Share a common transmission interconnection agreement
- Have a power sales agreement executed within 12 months of a similar facility in the same general vicinity
- Are operated and maintained by the same entity
- Are constructed by the same entity within 12 months
- Use common debt or equity financing
- Are subject to a revenue sharing arrangement

[3] AD16-16-000 Technical Conference Transcript, June 29, 2016 ("Tr.") at 65:25-66:3 (Commissioner Clark).

[4] The Commission's Notice of Proposed Rulemaking in Docket No. RM79-54 (FERC Stats. & Regs. [1977-1981 Proposed Regulations] ¶ 32,028 at 32,332 (June 27, 1979) would have established the one-mile rule as a rebuttable presumption. However, the Commission determined in Order No. 70 that "the requirement to rebut the presumption was burdensome and confusing" and revised the final rule "enable a small power producer . . . to apply to the Commission for a waiver for good cause" (FERC Stats. & Regs. ¶ 30,134 at 30,944).

- Obtain local, state and federal land use permits under a single application or as a single entity
- Share engineering or procurement contracts

We believe that PURPA and the Commission's regulations provide state regulatory agencies discretion and tools to address disaggregation. However, the Commission should clarify, perhaps via a Policy Statement, that state regulatory agencies have discretion and tools such as those described above. In the alternative, the Commission could revise its regulations to provide additional clarity. In response to Commissioner Clark's request, Tr. at 63:19-66:12, we attach Appendix A to our comments, which provides an example of how the Commission's regulations might be changed to make the presumption rebuttable.

2. Alternatively, should the Commission consider modifying the rule to either require projects seeking QF status to be spaced further apart or allowed to be closer together?

There is no "correct" distance that would—by itself—ensure the rule's effectiveness. First, the "right" allowed distance may depend on geography and climate, among other regional factors. Also, the allowed distance may need updates to account for advancements in technology and industry, or economic and societal changes. Without an ability to rebut the presumption using other criteria, such as those proposed by Commissioner Kjellander, changing the allowed distance would merely set a different distance around which a project's technical, financial or other structures could be manipulated. To avoid the adverse consequences of "manipulating" QF status through project disaggregation, states must have the discretion, using objective criteria, to determine whether multiple facilities in proximity to one another are separate QFs that fit within, or a single QF that exceeds, the 80 MW project capacity limit imposed by PURPA Section 201 and implemented in the Commission's regulations.

3. Should the Commission consider a more fact-based analysis based on criteria such as those proposed by Edison Electric Institute (EEI) and Idaho Commissioner Kjellander?

The Commission should allow states the discretion to engage in a fact-based analysis of a project's circumstances to determine whether multiple facilities in proximity to one another are separate QFs or a single QF. We continue to support the reasonable parameters proposed by EEI and Commissioner Kjellander. However, the parameters should be a guide, not a strictly-applied checklist, and the inquiry should be whether the proposed project adheres to PURPA's intent: to encourage <u>small</u> power production facilities—those of a maximum generating capacity of 80 MW at the same site. Because the inquiry requires evaluation of a multitude of factors, including region-specific factors, we believe the state commissions are in the best position to assume this analysis and determination.

4. Cooperative federalism: a federal-and-state solution to achieve PURPA's goals.

Based on the definitional language of PURPA Section 201 and the Commission's regulations, we believe that the state regulatory agencies must have responsibility and discretion to determine whether a proposed project meets or exceeds the 80 MW size limit placed on QF status by the statute and regulations. In order for this cooperative effort between the federal and state commissions to be effective, it is important to recognize all of PURPA's stated goals, which include ensuring reasonable rates that are in the public interest.

a. We must recognize all—and not just some—of PURPA's goals.

PURPA's goals are "(1) to encourage 'conservation of energy supplied by . . . utilities'; (2) to encourage 'the optimization of the efficiency of use of facilities and resources' by utilities; and (3) to encourage 'equitable rates to . . . consumers.'" *FERC v. Mississippi*, 456 U.S. 742, 746 (1982), *quoting* 16 U.S.C. § 2611 (other citations omitted). Consistent with these goals, section 210 of the statute "seeks to encourage the development of cogeneration and small power production facilities [that is, QFs]." *Id.* at 750, *citing* 16 U.S.C. § 824a-3 (other citations omitted). PURPA requires that rates paid for purchases from QFs "(1) shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and (2) shall not discriminate against [QFs]." 16 U.S.C. § 824a-3(b). As is evidenced by the great number of PURPA projects producing energy in Idaho, the IPUC fully supports and embraces these goals. However, encouraging development of QFs without regard for whether customers are paying equitable, just and reasonable rates is inconsistent with PURPA and the regulations and not in the public interest. This is precisely why regulators charged with implementing PURPA and the Commission's regulations must have adequate tools to ensure that the Act's intent is satisfied and that no single goal is advanced at the expense of others.

b. Duty to safeguard ratepayers from harm caused by manipulation through disaggregation.

In addition to encouraging development of QFs and resource optimization, we have a duty as regulators to ensure equitable, just and reasonable rates to consumers. As noted in our opening comments and at the technical conference, the Idaho PUC has seen the negative impacts to consumers' rates from projects that are disaggregated solely to qualify for more lucrative PURPA contracts. We have seen disaggregated projects seeking to stay under 80 MW to qualify for PURPA's avoided cost rates generally, as well as disaggregation to meet the lower threshold for standard published rate contracts. Disaggregation inevitably results in increased costs to consumers by increasing the number of projects eligible for PURPA contracts and avoided cost rates, including standard published rates. Comments of Commissioner Paul Kjellander at 4-6 (June 29, 2016) (Kjellander Comments); Tr. at 34-36.

As an example of the cost to ratepayers of PURPA purchase contracts, PacifiCorp, whose subsidiary, Rocky Mountain Power, is a public utility regulated by the IPUC, estimated in 2015 that it would be required under PURPA to purchase 39 million MW hours over the 2015-2025 time period, at a cost to ratepayers of $1.1 billion above market prices. "Discussion Draft on Accountability and Department of Energy Perspectives on Title IV: Energy Efficiency" Hearing before the Subcommittee on Energy and Power, Committee on Energy and Commerce, House of Rep., 114th Cong., Testimony of Paul Weisgall, Tr. at 28 (June 4, 2015). This cost is being incurred at a time when PacifiCorp does not forecast a need for additional generation until 2028. *Id.* at 27-28.

Idaho Power Company, another of the public utilities regulated by the IPUC, estimated in 2015 that its total PURPA purchase obligations, excluding approved but not yet constructed projects, was $2.6 billion over the life of the contracts. Pet. of Idaho Power Co. to Modify Terms and Conditions of Prospective PURPA Energy Sales Agreements at 3, Idaho PUC Case No. IPC-E-15-01 (Jan. 30, 2015). This was also at a time when the company did not forecast a need for capacity or energy until at least 2021. *Id.*

As a final example, in 2011 Rocky Mountain Power applied for an order accepting or rejecting a standard rate PURPA purchase contract with each of five disaggregated projects. App. of Rocky Mountain Power for Approval of Power Purchase Agreements between Rocky Mountain Power and Cedar Creek Wind, pt. 6, Idaho PUC Case No. PAC-E-11-05 (Jan. 10, 2011). Rocky Mountain Power explained that the group of five projects had originally been proposed as a single project, greater than 80 MW and not eligible for PURPA. *Id.* It then proposed two 78-MW projects, eligible for negotiated rates. *Id.* It then disaggregated further into five smaller projects, each separated by one mile, eligible for Idaho's standard published rate contracts at that time. *Id.* The company estimated that the cost impact of a group of five projects that had disaggregated to qualify for more favorable standard rate contracts was $10 million per year over the life of the contract ($10 million per year was the difference between standard published avoided cost rates and the negotiated avoided cost rates). *Id.*

The one-mile rule is currently a categorical standard that does not allow for consideration of other, potentially relevant factors to determine whether facilities are one or multiple QFs for purposes of FERC size limits. Projects with the same ownership, same energy source, same operations and interconnection dates, etc., that have been disaggregated in order to qualify as a PURPA project eligible under the 80 MW threshold, or for standard published rate contracts violate the Act and the regulations. Our review of these projects did not allow for inquiry into whether the facility was truly a *small* power production facility intended to receive the benefits of QF status under PURPA.

The following chart shows the wind projects brought before the IPUC in 2009 and 2010, for approval as standard rate 20-year contracts with deliveries not to exceed 10 aMW per month. They are grouped by common location (if a group had common ownership, each project within the group was at least one mile apart) and other shared characteristics, including contract date. The approved projects were each treated as separate QFs, although if tools had been available to perform a more fact-based analysis, a different result might have been reached in some cases. Disapprovals of contracts dated on or after December 14, 2010, were based on the contracts containing incorrect pricing contained in the contract.[5]

Project Name	**Location (approximate)**	**Utility**	**Contract Date**	**Date of Approval /Disapproval**	**Capacity (MW)**
Camp Reed Wind Park	Hagerman, Idaho	Idaho Power	9 Jul 2009	Approved 8 Oct 2009	22.5
Yahoo Creek Wind Park	Hagerman, Idaho	Idaho Power	9 Jul 2009	Approved 8 Oct 2009	21
Payne's Ferry Wind Park	Hagerman, Idaho	Idaho Power	9 Jul 2009	Approved 8 Oct 2009	21
Sawtooth Wind Project	Glenns Ferry, Idaho	Idaho Power	1 Sep 2009	Approved 16 Dec 2009	21
Power County Wind Park North	Power County, Idaho	PacifiCorp	18 Aug 2010	Approved 6 Oct 2010	21.78
Power County Wind Park South	Power County, Idaho	PacifiCorp	18 Aug 2010	Approved 6 Oct 2010	21.78
Cold Springs Windfarm	Mountain Home, Idaho	Idaho Power	12 Nov 2010	Approved 23 Dec 2010	23
Desert Meadow	Mountain Home, Idaho	Idaho Power	12 Nov 2010	approved	23.

[5] As of December 14, 2010, standard rate contract pricing was only available to wind and solar projects producing 100 kW or less (the threshold for standard rates had been 10 aMW prior to December 14, 2010). IPUC Order No. 32260.

Project Name	Location (approximate)	Utility	Contract Date	Date of Approval /Disapproval	Capacity (MW)
Windfarm				23 Dec 2010	
Hammett Hill Windfarm	Mountain Home, Idaho	Idaho Power	12 Nov 2010	Approved 23 Dec 2010	23
Mainline Windfarm	Mountain Home, Idaho	Idaho Power	12 Nov 2010	Approved 23 Dec 2010	23
Ryegrass Windfarm	Mountain Home, Idaho	Idaho Power	12 Nov 2010	Approved 23 Dec 2010	23
Two Ponds Windfarm	Mountain Home, Idaho	Idaho Power	12 Nov 2010	Approved 23 Dec 2010	23
Deep Creek Wind Park, LLC	Rogerson, Idaho	Idaho Power	10 Dec 2010	Approved 11 Feb 2011	20
Cottonwood Wind Park LLC	Rogerson, Idaho	Idaho Power	10 Dec 2010	Approved 11 Feb 2011	20
Rogerson Flats Wind Park LLC	Rogerson, Idaho	Idaho Power	10 Dec 2010	Approved 11 Feb 2011	20
Salmon Creek Wind Park LLC	Rogerson, Idaho	Idaho Power Idaho Power	10 Dec 2010	Approved 11 Feb 2011	20
Coyote Hill / Cedar Creek LLC	Bingham County, Idaho	PacifiCorp	22 Dec 2010	Approved 21 Dec 2011	26.7
North Point / Cedar Creek LLC	Bingham County, Idaho	PacifiCorp	22 Dec 2010	Approved [6] 21 Dec 2011	80
Five Pine / Cedar Creek LLC	Bingham County, Idaho	PacifiCorp	22 Dec 2010	Approved 21 Dec 2011	26.7
Rattlesnake Canyon / Cedar Creek LLC	Bingham County, Idaho	PacifiCorp	22 Dec 2010	Disapproved 21 Dec 2011	27.6
Steep Ridge / Cedar Creek LLC	Bingham County, Idaho	PacifiCorp	22 Dec 2010	Disapproved 21 Dec 2011	25.3
Murphy Flat Mesa	Murphy, Idaho	Idaho Power	15 Dec 2010	Disapproved 8 Jun 2011	25
Murphy Flat Energy	Murphy, Idaho	Idaho Power	15 Dec 2010	Disapproved 8 Jun 2011	25
Murphy Flat Wind	Murphy, Idaho	Idaho Power	15 Dec 2010	Disapproved 8 Jun 2011	25
Rainbow Ranch Wind	Declo, Idaho	Idaho Power	15 Dec 2010	Disapproved 8 Jun 2011	23
Rainbow West Wind	Declo, Idaho	Idaho Power	15 Dec 2010	Disapproved 8 Jun 2011	23
Grouse Creek Wind Park	Lynn, Utah	Idaho Power	28 Dec 2010	Disapproved 8 Jun 2011	21
Grouse Creek Wind Park II	Lynn, Utah	Idaho Power	28 Dec 2010	Disapproved 8 Jun 2011	21
Alpha Wind	Burley, Idaho	Idaho Power	15 Dec 2010	Disapproved 8 Jun 2011	29.9
Bravo Wind	Burley, Idaho	Idaho Power	15 Dec 2010	Disapproved 8 Jun 2011	29.9
Charlie Wind	Burley, Idaho	Idaho Power	15 Dec 2010	Disapproved	27.6

[6] Ultimately, in a settlement approved by the IPUC, the five Cedar Creek projects were reduced to three projects (Coyote Hill, North Point, and Five Pine), at standard (published) avoided cost rates; applications to approve the Rattlesnake Canyon and Steep Ridge projects were withdrawn. *See* IPUC Order No. 32419.

Project Name	Location (approximate)	Utility	Contract Date	Date of Approval /Disapproval	Capacity (MW)
				8 Jun 2011	
Delta Wind	Burley, Idaho	Idaho Power	15 Dec 2010	Disapproved 8 Jun 2011	29.9
Echo Wind	Burley, Idaho	Idaho Power	15 Dec 2010	Disapproved 8 Jun 2011	29.9

The circumstances of these projects suggest that they were disaggregated to qualify for the more favorable (higher) standard rate, or to take advantage of PURPA's must-purchase obligation—at a cost to ratepayers. They are precisely the type of projects that should be reviewed for a determination whether they satisfy the intent of PURPA Section 201 and the Commission's implementing regulations. To protect the state's retail ratepayers, state regulatory commissions need the ability and discretion to determine whether a QF is manipulating its project contrary to PURPA's and the regulations' intent.

c. Solution: fact-based, discretionary determination that a project satisfies the rule's intent.

During the technical conference, Commissioner Clark asked whether anyone cared to defend disaggregation. Tr. at 65. No one responded. Later, Todd Glass, representing the Solar Energy Industries Association, stated that he would not want changes to the one-mile rule to "eliminate the value of economies of scale." Tr. at 66. Mr. Glass continued "we don't want abuse and nobody in the solar industry [wants to] play games or abuse the . . . one-mile rule," adding, "we do want to encourage the efficient development of strong players that can actually follow through on their commitments and deliver . . . renewable power to the grid." Tr. at 67. Also, Laura Chappelle, representing the Independent Power Producers Coalition of Michigan, stated that she wanted to defend the one-mile rule "in the context of existing facilities," then clarified that she hoped whatever the Commission did would "lend some clarity and [not] affect existing resources who have very real reasons for being a mile or less apart." *Id.*

About the one-mile rule, Don Sipe, representing the American Forest and Paper Association, stated that if somebody is "trying to use the rules to get me a better deal . . . that doesn't sound like gaming to me." Tr. at 153. Mr. Sipe considered, "What is it that I'm being deprived of by having that other project within a mile?" then continued, "what we want to see is . . . projects built that are the lowest cost, that have the best chance of working out in the market." *Id.* In our view, the problem with this scenario and disaggregation in general is that the price the utility (and ultimately its customers) pay for PURPA projects is not based on project cost—it is based on avoided cost; and the use of disaggregation to qualify for standard rates leads to projects receiving an even higher avoided cost rate. Disaggregation and "lower project costs" do not lead to ratepayers getting a better deal.

State regulatory agencies need clarity and guidance from the Commission as to how facilities should be evaluated for purposes of determining compliance with PURPA's and the regulations' size limits. Guidance is also needed regarding any other tools available to the state regulatory agencies in their efforts to enforce PURPA and the regulations. This need was echoed throughout pre-technical conference comments and at the technical conference itself. *See* Tr. at 45 (Commissioner Kjellander), 46-47 (Joe Schmidt, of Alliant Energy, representing EEI), 47 (Todd Glass), 48 (Allison Clements, representing the Sustainable FERC Project); Comments of the Industrial Energy Consumers of America at 4 (Sept. 14, 2016). As noted above, we believe the intent of the one-mile rule was to ensure that QFs that truly meet the law's requirements—that is, small power production facilities of 80 MW or less and cogeneration facilities—receive the benefits of the law. We suggest that the Commission make this intent clear.

As proposed above and in our prehearing comments, a set of guidelines would provide QFs with some predictability as they develop their projects and would provide state regulatory agencies tools to ensure that the statute and regulations are implemented as Congress and the Commission intended. Any parameters must be guidelines only. If the parameters are a definitive test, then they would defeat the state's discretion and ability to address disaggregation.

To successfully deter manipulation through disaggregation and effectively implement the Act, the state regulatory agencies must have discretion to determine whether a project is truly a small power producer or instead a large developer that has disaggregated a single project into multiple facilities in order to maximize its profit at the expense of the utility's ratepayers.

5. Summary

As we expressed at the technical conference and in our prefiled comments, the IPUC believes in the intent and goals of PURPA. Tr. at 34, 141, 144; Comments of Commissioner Kristine Raper at 1-2 (June 29, 2016) (Raper Comments); Kjellander Comments at 2-3 (June 29, 2016). To ensure that PURPA's goals are being advanced symbiotically with—and not to the detriment of—the interests of electricity ratepayers, the states should be given discretion to address problems arising from disaggregation that is contrary to the Act's intent. For this reason, we believe that the presumption in the rule should be made rebuttable, with the burden on the facility seeking certification, to demonstrate it is satisfying the intent of the rule. The state commissions should have the duty of presiding over such challenges, and discretion to do so.

B. <u>Minimum Standards for PURPA Purchase Contracts</u>

PURPA requires the Commission's regulations to ensure that rates paid for purchases from QFs "(1) shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and (2) shall not discriminate against [QFs]." 16 U.S.C. § 824a-3(b). In addition, PURPA requires that the purchase rate shall not exceed the "incremental cost" to the utility, defined as the cost of electric energy which, "but for the purchase from [the QF], such utility would generate or purchase from another source." *Id*. §§ 824-3(b), (d). The Commission's regulations repeat these requirements and adopt the "avoided cost" definition and construct. 18 C.F.R. §§ 292.304(a), 292.101(6). In Order No. 69, the Commission elaborated on the avoided cost requirement, explaining that its mandate under PURPA Section 210(a) is to ensure that "the total costs to the utility and the rates to its other customers *should not be greater* than they would have been had the utility not made the purchase from the qualifying facility or qualifying facilities." Order No. 69, FERC Stats. & Regs. ¶ 30,128 at 30,868 (1980)(emphasis added) (explaining why it would not change its rule in 18 C.F.R. § 292.301 to address cogenerators and small power producers who entered into contracts prior to the promulgation of Order 69 under terms and conditions that might be less favorable than those available under Order 69). As the Commission described it, "the intention [of Congress] was to make ratepayers indifferent as to whether the utility used more traditional sources of power or the newly encouraged alternatives." *Southern Cal. Edison, San Diego Gas & Elec.*, 71 FERC ¶ 61,269 at 62,080 (1995).

The Commission has requested comment regarding minimum standards for PURPA purchase contracts. *See* Notice, 81 Fed. Reg. 64455. In summary, any minimum requirements for PURPA-purchase contracts must give equal priority to PURPA's requirements of encouraging QF development and ensuring that rates to consumers are just and reasonable and in the public interest. Each state's regulatory agency is in the best position to ensure that these competing requirements are met, considering the unique circumstances in each state. If the Commission chooses to adopt guidelines or terms and conditions, it should ensure state regulatory agencies retain the discretion and tools to ensure that rates to consumers remain just and reasonable. We provide comments on the specific questions raised by the Commission below.

We believe that under PURPA and the Commission's regulations, state agencies currently have discretion and limited tools with which to meet regulatory obligations. However, the Commission should clarify, perhaps through issuance of a Policy Statement, that state regulatory agencies have the discretion necessary to meet their regulatory obligations. Alternatively, the Commission could amend its regulations to provide the additional clarity. In response to Commissioner Clark's request, Tr. at 66, we provide an example of how the Commission's regulations might be changed in Appendix A.

1. There may not be a single appropriate minimum length of a PURPA purchase contract or other minimum contract terms and conditions.

Several panelists at the technical conference and commenters took the position that fixed avoided cost rate contracts must be "long-term" in order for QF developers to obtain financing or otherwise incent generation to be built. *See* Tr. at 100-101 (Todd Glass), 164-165 (Don Sipe), 186-187 (Todd Foley), 184 (John Hughes). In their conference remarks or written comments, Todd Glass and Thomas Melone indicated that contracts must be 15 years or more to be financeable. Tr. at 100-101 (Todd Glass); Comments of Allco Renewable Energy Ltd., at 2 (June 7, 2016). However, thus far we have not seen evidence (financial statements or otherwise) to demonstrate that this is the case. *See* Tr. at 171 (Commissioner Raper).

Other commenters, including Commissioner Raper, explained that long-term fixed-rate contracts lead to the utility's customers paying more for the QF purchase than they would have otherwise, in violation of PURPA. *See* Tr. at 126-127 (Jeff Burleson) and 142-144 (Commissioner Raper); Comments of the Honorable Travis Kavulla at 6 (June 29, 2016); Comments of Al Brogan at 4-5 (June 29, 2016). This overpayment occurs because the projected avoided cost rate that is fixed at the time of contracting has proven to be, over time, higher than the utility's ongoing avoided costs. In this situation, ratepayers are not held indifferent.

In the Idaho PUC's experience, avoided cost rates for larger QFs[7] are declining and will continue to decline in the future. *See* Raper Comments at 3-4; Idaho PUC Order No. 33357 at 22 (Aug. 20, 2015); Idaho PUC Order No. 33419 at 6, 17-19. When a utility signs a long-term contract with a QF with a locked-in avoided cost rate, and the utility's actual avoided costs are *lower* in year 10 of the contract, then the utility is paying more than its avoided costs, and its customers are paying *higher* rates due to that QF purchase contract and locked-in rate. This is contrary to the intent of PURPA and the Commission's express regulations. It results in rates that are not just, not reasonable, and not in the public interest—in short, rates that are not consistent with the requirements of PURPA Section 210(b) (16 U.S.C. § 824a-3(b)). State regulatory agencies need the discretion and tools to balance the interests expressed in the Act.

Shorter term PURPA purchase contracts can provide a useful and effective safeguard for the justness and reasonableness required by PURPA Section 210(b)(1). With a shorter term, the must-purchase obligation implemented by 18 C.F.R. § 292.303(a) ensures that the contract will be renewed for subsequent terms, for as many terms as the QF wants, with only the avoided cost rate subject to

[7] By "larger QFs," we mean those not subject to standard published rates.

adjustment each term. Alternatively, longer term contracts can provide a solution to the problem of the divergence of an historic avoided cost from just and reasonable rate levels on a current basis if the avoided cost rate in the contract is subject to adjustment during the term of the contract.[8] Both approaches encourage QF development because the QF has a mandatory purchaser for as long as the QF produces energy.

Several panelists in the technical conference and commenters voiced similar concerns or made similar suggestions. As Jeff Burleson of Southern Company put it, "[t]he combination of increased uncertainty around natural gas prices and the growing share of natural gas combined cycle generation have increased the risk of economic harm to retail customers associated with locking in long-term avoided energy cost payments based on projections of natural gas prices and associated avoided electricity energy costs." Comments of Jeff Burleson at 6 (June 29, 2016). Mr. Burleson added that outside of the PURPA context, Southern Company generally does not enter into long-term contracts with fixed energy rates—instead, to minimize risk to customers, Southern Company enters into shorter term contracts, or long-term contracts in which the energy rate is linked to market prices and is adjustable. Tr. at 167-168, 200-201.

Al Brogan, representing the Edison Electric Institute (EEI), identified the same risk, stating

> [t]he various [avoided cost calculation] methods . . . routinely fail to reflect dynamic market conditions and often force utilities to enter into long-term contracts at prices that are substantially above-market, the costs of which are then passed through to our customers. This problem is only exacerbated by the mandatory purchase obligation that requires utilities to purchase power from a QF even if the power is not needed.

Comments of Al Brogan at 4 (June 29, 2016). He explained that as a result, utilities with large amounts of QF power must often curtail or shutdown less expensive generation in order to take the higher-cost QF power. *Id.* Mr. Brogan explained that the primary reason for the difference between QF pricing and a utility's actual avoided cost of energy is the requirement that QFs be allowed to lock-in a fixed-price for a long-term contract. *Id.* at 10. While those prices have remained fixed, the prices for clean energy resources have declined significantly. *Id.* These long-term fixed-price QF contracts are resulting in costs to consumers that are higher than they otherwise would have been, contrary to the intent of PURPA.

Mr. Brogan presented EEI's suggestion for remedying this problem: change the Commission's regulations to require that avoided cost <u>energy</u> rates will be based on utility's avoided costs calculated at the <u>time of delivery</u>, and that the avoided cost <u>capacity</u> rates will be calculated either at the time of delivery or when the legally enforceable obligation is incurred, but not more than 12 months prior to the time of delivery. *Id.* at 5.

Travis Kavulla of the Montana Public Service Commission and commenting on behalf of the National Association of Regulatory Utility Commissioners, identified the same risk in his earlier

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[8] The Idaho PUC has not adopted this latter approach because it is our interpretation that the Commission's regulations do not allow for it. *See* 18 C.F.R. § 292.304(d)(2). The Commission's regulations state that a QF has the option "[t]o provide energy or capacity pursuant to a legally enforceable obligation . . . over a specified term." *Id.* In that case, the QF has the option of electing for its rates to be based on the avoided costs calculated at the time of delivery or on the avoided costs "<u>calculated at the time the obligation is incurred</u>." *Id.* Section 292.304(d)(2)(ii)(emphasis added). We have interpreted "calculated at the time the obligation is incurred" to mean that an avoided cost rate is calculated *and then fixed* for the specified term. *See also Freehold Cogen. Assocs. v. Bd. of Reg. Comm'rs*, 44 F.3d 1178, 1192 (3rd Cir. 1995) *citing* 18 C.F.R. § 385.602(c) (exempting qualifying facilities from state laws regulating rates of electric utilities).

comments. Comments of the Honorable Travis Kavulla at 6 (June 29, 2016). Commissioner Kavulla suggested that shorter term avoided cost calculations could be appropriate in certain situations, such as where resource solicitations are routinely held and genuinely competitive for needs identified in a utility's IRP or where a utility, in its IRP, does not forecast a need for an additional owned or long-term contracted energy resources for the next five to seven years. *Id.* at 9.

These examples illustrate the point that regardless of what term length may be most beneficial for financing a QF, a long-term contract with a fixed avoided cost rate can result in customers paying *more* than they otherwise would have. This is not what PURPA envisions. A different solution, like one of those discussed above, is needed to protect customers and still encourage QF development. The contract length and other terms and conditions must give equal priority to encouraging QF development and ensuring that customers remain indifferent as to whether a utility uses more traditional resources or purchases from a QF.

The Idaho PUC believes that a variety of factors have led to the prolific development of QFs. Long-term PURPA purchase contracts with favorable avoided cost rates may not be the sole driver. Other factors may include federal and state tax incentives, such as the federal production tax credit and investment tax credit, state Renewable Portfolio Standards and other policies, or a utility need for new generation (that is, through an Integrated Resource Plan or competitive bidding process). Any rules regarding PURPA contract length or other terms and conditions should allow each state's regulatory agency the discretion to consider the circumstances and factors at play in that state, and to craft policies and solutions that meet the two goals of encouraging QF development and ensuring that customers' rates are just and reasonable and in the public interest.

Finally, while we acknowledge that availability of financing may be an important factor in encouraging the development of QFs, other PURPA requirements continue to encourage QF development. Such requirements include the mandatory purchase obligation, which ensures a long-term purchaser for the QF's power; the obligation to purchase at avoided cost rates (even if they may be subject to adjustment); and the exemption for QFs from certain federal and state ratemaking standards. 16 U.S.C. § 824a-3(a), (b), and (e); 18 C.F.R. §§ 292.303, 292.304, and 292.601, 292.602. These requirements are enumerated in the statutory and regulatory language—ensuring of the availability of financing is not. In any case, the PUC's task is to (1) encourage the development of QFs, including by ensuring that rates do not discriminate against QFs (*See* 18 C.F.R. § § 292.304); (2) ensure that rates to customers are just and reasonable and in the public interest (*Id.*; *Idaho Code* §§ 61-301, 61-502); and (3) outside the PURPA context, ensure that utility investments included in rate base are used and useful, that expenses included in rates were prudently incurred, and that utility service is adequate and reliable (*See, e.g.*, *Idaho Code* §§ 61-302, 61-502A). For these reasons, state PUCs must have discretion and tools to set contract lengths, terms, and conditions that result in rates to consumers that are just, reasonable, and in the public interest, and that encourage QF development.

2. Establishing a required minimum contract length or other required contract terms and conditions may affect QF development. The requirement to encourage QF development must be given equal weight with the mandate to ensure that rates to consumers are just and reasonable and in the public interest.

The goal of encouraging QF development must be given equal priority with the requirement to ensure that rates to customers are just and reasonable and in the public interest. 16 U.S.C. § 824a-3(a) and (b). Any minimum required contract length or contract terms and conditions must ensure that customers remain "indifferent" to the purchase from the QF. If a minimum required contract length or other required terms and conditions result in rates to customers that are higher than they otherwise would have been, the purpose of the Act will not be achieved. Any changes to the requirements must ensure that customers' rates remain just and reasonable.

3. **The 100 kW minimum size threshold for requiring standard rates, and the states' discretion to set a higher threshold, are appropriate.**

The minimum size threshold for requiring standard rates set forth in the Commission's regulations is 100 kW. 18 C.F.R. § 292.304(c)(1). The states have discretion to establish a higher nameplate capacity cap on the availability of standard rates. *Id.* § 292.304(c)(2). The Idaho PUC believes that the 100 kW minimum size threshold set forth in the Commission's regulations, in conjunction with the states' discretion to adopt higher thresholds, is appropriate. Each state's regulatory agency is in the best position to evaluate the circumstances in that state and determine whether the minimum threshold or a higher one is appropriate to achieve PURPA's goals.

4. **Utilities do provide the data to be used in avoided cost calculations, as described in Sections 292.302 and 292.304(e) of the Commission's regulations.[9] The calculations, in and of themselves, are not the problem.**

In our experience, utilities provide the required information and it is useful and helpful in calculating avoided cost rates. Our concern is not necessarily with the calculation itself. As discussed above, our concern is that locking in the calculated rate for a long-term period, when we know that the calculation will soon be outdated and result in a contract price that exceeds actual avoided costs, leads to unjust and unreasonable rates to consumers. Each state regulatory agency must have discretion and tools to allow it to ensure that all its statutory mandates are met.

C. <u>Conclusion</u>

As expressed in our prehearing comments, Idaho has abundant and available renewable resources, including hydropower, geothermal, solar, wind, and cogeneration resources. Raper Comments at 1. Idaho's richness in renewable resources ensured us a leading role in tackling the challenges of how to implement PURPA. While the IPUC enjoyed minimal regulatory excitement during PURPA's first 25 years, the amount of PURPA generation for Idaho's two largest investor-owned utilities (Idaho Power and PacifiCorp) increased six- and seven-fold respectively, since 2007, resulting from advancements in conservation, energy efficiency, and technology, as well as federal and state tax incentives. *Id.* at 2; *see* Kjellander Comments at 1. Given our involvement in the development of PURPA to date, we appreciate the opportunity to provide these comments and participate in the technical conference. We hope to help shape PURPA's next 25 years and beyond.

The IPUC fully supports and embraces all of PURPA's goals, including the advancement of renewable energy and energy conservation, the promotion of optimal efficiency in the use of utility resources, and the encouragement of equitable consumer rates in the public interest. *See FERC v. Mississippi*, 456 U.S. at 746; 16 U.S.C. §§ 2611, 824a-3(b). <u>We believe PURPA remains an important piece of the statutory and regulatory framework concerning energy in this country and in Idaho</u>. We have made every effort to work within the statutory and regulatory framework to resolve issues of

[9] 18 C.F.R. §§ 292.302, 292.304(e) (2015).

PURPA's implementation in Idaho. We recognize, like many others, that in the years since PURPA was passed there have been many changes in the energy industry and that, in today's marketplace, there are avenues for the development of QFs apart from PURPA that did not exist previously. Given the changed circumstances, state regulatory agencies need discretion and tools to continue to be able to implement PURPA effectively considering the facts of each case.

In addressing the issues raised in this technical conference, we urge the Commission not to eliminate the existing tools that we and other state regulatory agencies have successfully used to balance and fulfill our regulatory obligations. Instead, we propose that the Commission clarify the intent of its regulations, and allow the state agencies broader discretion to implement them, in keeping with the Commission's intent. Certain clarifications to the one-mile rule and to the regulations regarding avoided cost pricing would be helpful to ensure that *all* of PURPA's goals can be advanced. With the clarifications, state regulatory agencies would have the discretion and the tools to more successfully implement the statute and the Commission's regulations and ensure the viability of PURPA and the advancement of PURPA's goals well into the future.

2016 Major Events

Permissive 10-digit dialing launched Nov. 5 in preparation for Idaho's second area code

Case No. GNR-T-15-06

October 28, 2016 – Beginning Nov. 5, Idahoans started getting accustomed to 10-digit dialing when placing local calls. That date kicked off a nine-month "permissive dialing period," before mandatory 10-digit dialing begins in August 2017 to accommodate a second area code in the state.

The second area code – "986" – will be issued to new telephone numbers beginning in the fall of 2017. Assigning the 986 code to only new numbers means that no existing numbers will need to be changed. However, all users will need to dial 10-digits (area code, plus prefix, plus 4-digit number) to have calls completed. Long-distance or toll calls on landlines will require a "1" before the area code, the same as long-distance calls now require.

The second area code is necessary because numbers under the 208 code are running out, due primarily to increased use of cell phones, the Internet, Voice over Internet Protocol (VoIP), and other advancing technologies.

The nine-month permissive dialing period will also include an educational campaign from telecommunication providers.

"The commission, as well as the telecommunications industry, wanted to allow plenty of time for customers to prepare for the change and get used to 10-digit dialing," said Paul Kjellander, president of the Idaho Public Utilities Commission.

Most telecommunications devices, even landline phones, now have number storage capability that allows customers to program numbers into their phones and reach their contacts with the press of one or two buttons. Over the next nine months, customers should change the numbers they have programmed into their phones to include the area code. When mandatory 10-digit dialing begins next August, all calls, even local calls, without an area code will not be completed. Callers will get a recording telling them to hang up and dial again and include the area code.

Local calls on landline phones will still not cost anything, even though dialing the area code will be required. The move to a second area code will not impact rates.

Callers will still dial just three digits when calling 911, 211, 411 and 811.

Customers should ensure all services such as automatic dialing equipment, software or other types of equipment recognize 986 as a valid area code. Examples include life-safety systems, facsimile machines, Internet dial-up numbers, alarm and security systems, security gates, ankle monitors, speed-dialers, call-forwarding settings and voicemail services. Contact your medical alert or security provider if you are not sure whether your equipment needs to be reprogrammed to accommodate 10-digit dialing.

Idaho is one of few states that still has one area code. The 208 code was issued in 1947. In August 2001, Neustar, Inc., the administrator of the North American Numbering Plan, projected that Idaho would run out of available numbers under its 208 area code by 2003. In response, the commission implemented various numbers conservation plans that have been successful in delaying a second area code by 15 years.

While the commission acknowledged that 10-digit dialing may be inconvenient for some, the move to 10-digit dialing is inevitable due to advancing technology, regardless of whether Idaho had to acquire a second area code. Developing technology “will eventually drive seven-digit dialing into obsolescence,” 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.”

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QUICK FACTS: Idaho’s Area Code

- Idaho telecommunications providers were informed in 2015 that Idaho’s “208” area code is projected to exhaust by mid-2018, necessitating a second area code by no later than Fall 2017. The second area code will be “986.” There is no impact on rates.

- Idaho has been able to avoid a second area code for 16 years. The state was informed in 2001 that the area code would exhaust by 2003. The commission implemented a numbers conservation plan in the Boise metro area that worked until 2007 when the state was notified that the area code would exhaust in 2010. The commission then extended the numbers conservation plan statewide, bringing us to a mid-2018 exhaust. As of August, 95.5% of available numbers have been assigned.

- In June 2016, Idaho’s telecommunications providers asked the Idaho PUC to begin a 16-month implementation period for a second area code. Beginning **Nov. 2, 2016,** customers can begin using 10-digit dialing. If you forget and dial seven digits, your call will still be completed. Beginning **Aug. 5, 2017,** customers must use 10-digit dialing or you will receiving a recording asking you to hang up and dial again. Beginning **Sept. 5, 2017**, new numbers may be assigned using the 986 area code.

- The commission had two options to implement a second area code. An <u>all-services</u> <u>overlay</u> would superimpose a new area code over the entire state, but assign it to <u>new numbers only</u>. All existing callers would retain their 208 area code and their original number. However, this method requires 10-digit dialing for all calls: area code, prefix and four-digit number.

- The <u>geographic split</u> would have divided the state into two regions with the new area code assigned to one region. Citizens in the region assigned the new area code would be required to change their telephone numbers. Ten-digit dialing would not be required for calls within the same area code.

- The all-services overlay was the unanimous recommendation of Idaho telecommunications providers. No state in the last decade has chosen the geographic split. In its Order issued Nov. 2, 2016, the PUC adopted the all-services overlay and a schedule for its implementation. The commission’s Order is here:

http://www.puc.idaho.gov/fileroom/cases/tele/GNR/GNRT1506/ordnotc/20151102FINAL_ORDER_NO_33414.PDF . A press release summarizing the Order is here: http://www.puc.idaho.gov/fileroom/cases/tele/GNR/GNRT1506/staff/20151102PRESS%20RELEASE.PDF

- The industry's Best Practices recommendation accepted by the Federal Communications Commission cites these benefits to an all-services overlay:
  - All existing customers would retain their current area code and would not have to change their existing numbers.
  - Does not require about half of customers to change their numbers, thus creating winners and losers and avoiding statewide conflict over who retains the existing area code and who must adapt to a new number.
  - Less financial impact on business customers because there is no need to change signage, advertising, stationery, business cards and billing forms. No discrimination by forcing some business customers to incur significant expense that other business customers do not.
  - Does not split legislative districts, cities, counties and school districts into different area codes.
  - No technical impacts to number portability, text messaging or multi-media messaging.
  - Less customer confusion and an easier education process.
  - Avoids negative impacts to E-911, industry and alarm system databases that would have to be updated with new numbers.
  - Avoids negative impacts to directories and directory assistance databases.
  - While an all-services overlay would require 10-digit dialing, technological advances, especially in Voice over Internet Protocol (VoIP) will require everyone to move to 10-digit dialing anyway, likely within the next decade.

While 10-digit dialing will be an adjustment and may appear inconvenient, most all phones, both landline and cellular, can now be programmed to automatically dial 10-digits with the press of just one or two numbers for all the people you frequently call.

2016 Major Events

PUC gives green light to community solar project

Case No. IPC-E-16-14, Order No. 33638

November 3, 2016 – The commission approved an Idaho Power application to build a 500-kilowatt community solar project in southeast Boise.

The $1.16 million single-axis solar project on the southwest corner of Amity and Holcomb roads will allow up to 1,093 residential customers and 470 non-residential customers to buy one or more subscriptions (one subscription is a 320-watt panel) for the solar farm's anticipated 25-year life. Completion of the project is anticipated by June 2017.

Some 350 kilowatts of the 500-kW project will be apportioned to residential customers and 150-kW for commercial customers. Subscriptions will be rewarded on a first-come, first-served basis until program capacity is reached.

Commission staff and parties to the case, including the Idaho Conservation League, the Idaho Irrigation Pumpers Association, the Sierra Club, Snake River Alliance and the City of Boise, differed with Idaho Power's initial subscription fee proposal and the method that would be used to calculate the monthly credit subscribers would get for their part of the solar generation.

The parties engaged in settlement discussions to work out their differences. Members of the public also provided comment.

"The record demonstrates that there is great interest and enthusiasm" for the program, the commission said. "We appreciate the intervening parties' willingness to engage in settlement negotiations to address the various concerns raised … In this way, the public interest is best served," the commission said. It also thanked citizens who provided input. "Our service to the public in hearing and deciding these matters is better informed when it includes input from the public itself."

Idaho Power originally proposed a one-time fee of $740 for each subscription. After negotiation, the company and parties agreed on $562, while also allowing customers to pay either at one time or in monthly installments of $26.31 over 24 months.

Parties also said the company's proposed 3-cent per kWh credit would not be enough for subscribers to recoup their investment. Idaho Power originally proposed the credit be calculated based on the embedded cost-of-service to serve each customer class. But commission staff and other parties said that method does not take into account the value that a new generation resource provides to Idaho Power's system, particularly a solar resource that provides energy during high-use hours of the day.

Because Idaho Power operates its system to minimize ratepayer costs, a new generation project would allow the company to avoid using its most expensive resource, thus providing greater value than just embedded cost-of-service. Therefore, the credit given to customers should be based on an avoided-cost calculation and not on embedded cost-of-service, commission staff and other parties maintained.

Every two years, Idaho Power files an Integrated Resource Plan, which includes an avoided-cost calculation for its energy efficiency and demand-side management (DSM) programs. Commission staff and parties proposed that Idaho Power base the customer credit on that biennial calculation. The calculation of DSM avoided costs is more current because it is updated every two years, whereas embedded cost-of-service studies are updated only when the utility files a rate case, which for Idaho Power, was five years ago.

Eventually, the company and parties agreed on a solar energy credit that reflects Idaho Power's recommended embedded cost of energy, but one that gradually increases as the retail energy rate increases. Idaho Power projects the credit could increase from about 3 cents now to about 4.4 cents in 25 years. The credit is in the form of a reduction in kilowatt-hours billed customers based on the previous month's solar generation. The total monthly credits given over 12 months cannot exceed that subscriber's energy use from the prior year.

The parties agreed to reduce the subscription fee to include 1) the net present value of the difference between the DSM avoided costs – which include energy and capacity – and the forecasted embedded costs over the 25-year life of the project, 2) the value of deferred transmission and 3) the removal of the cost of smart inverters. These benefits, plus the original agreement from Idaho Power shareholders to contribute 15 percent of project costs ($175,000), brought the subscription down from $740 to $562.

The project was requested by Idaho Power customers who cannot install their own rooftop solar panels because they live in rental properties or multi-unit dwellings, have aging rooftops, too much shading or an unsuitable rooftop orientation.

Both Idaho Power and the commission said the pilot status of the program will help the company and commission develop future, perhaps larger, projects. Small-scale pilot programs, the commission said, "are valuable for learning what works and what does not." Idaho Power said the pilot will assist the utility in learning the "complexities associated with offering community solar programs including: customer commitment, construction, contracting, interconnection, maintenance and billing."

Idaho Power will retain ownership of the Renewable Energy Credits (RECs) and all other environmental attributes. The RECs would be retired by Idaho Power on behalf of subscribers.

2016 Major Events

Idaho Power seeks OK to join western EIM by April 2018

Case No. IPC-E-16-19, Order No. 33595

Sept. 20, 2016 – Idaho Power Company is taking the initial steps toward possible entry into an Energy Imbalance Market (EIM), which would allow it to pool its generation with neighboring entities to more accurately match production to demand. The move could reduce power supply costs to customers by as much as $4 million to $5 million annually, according to an independent estimate.

The utility is asking the commission to make a finding that its participation in the EIM could benefit customers in the long-term, authorize a deferral account to track the costs and allow the company to recover those costs from customers in a future rate case. Idaho Power hopes to join the EIM in April 2018.

Utilities like Idaho Power typically begin each hour with generation to match its anticipated load. But during the hour, imbalances occur when the supply of energy does not equal demand. When that happens, Idaho Power relies on dispatches from its own generation and extra reserves to balance supply with demand.

By joining the EIM, administered by the California Independent System Operator (CAISO), Idaho Power would have access to an automated five-minute energy dispatch service across a broader footprint in the West with many more deployable resources.

Idaho Power would be joined with neighboring utilities, such as PacifiCorp and NV Energy, to balance supply and demand more efficiently and cost-effectively. Joining the EIM does not mean that Idaho Power would give up its control over its own generating resources, but it would no longer independently operate its own generation dispatch.

Idaho Power claims that participation in the EIM will likely result in cost savings that will benefit customers over the long-term. Moving from an hourly market to a five-minute imbalance market is expected to lead to increased surplus sales opportunities when Idaho Power is generating more electricity than it needs as well as cost savings from increased access to other suppliers' lower-cost generation.

Further, Idaho Power claims, the EIM would allow for more efficient integration of intermittent wind and solar resources, which currently make the management of energy imbalance more complex. The renewable energy could be dispatched to serve customers in other service territories helping to prevent curtailment of intermittent resources, which would benefit wind and solar operators.

According to Idaho Power, the increased sales and lower cost power supply would lead to lower net power supply expense for the company, 95 percent of which is passed on to customers. The company's supporting testimony also indicates that participation in the EIM may result in improved transmission congestion and enhanced reliability.

An independent consultant contracted by Idaho Power claims the potential cost savings of participation in the regional market could be between $4 million and $5 million per year.

But there are upfront costs, estimated to be about $11.1 million, which includes start-up expense of $1.7 million, software integration costs of $7.9 million and metering investment of $1.5 million. In addition to the upfront expense, is the ongoing operational expense of about $836,000 annually for labor and ongoing market and hosted software fees of about $786,000 per year beginning in April 2018.

Idaho Power claims the net decrease in power supply costs will more than offset start-up and operational expenses. Idaho Power is proposing to defer collection of start-up costs until after participation in the EIM begins and benefits start flowing to customers.

The Western EIM was created by CAISO and PacifiCorp in 2014. Since then, NV Energy has joined along with Puget Sound Energy and Arizona Public Service Company. Portland General Electric is scheduled to join in October 2017.

The EIM is governed by a five-member body that is financially independent from market participants. Members are selected by a nominating committee that includes several stakeholders, including EIM participants, transmission owners, suppliers and marketers of generation, publicly owned utilities, state regulators and public interest and consumer advocate groups.

2016 Major Events

Rwanda Utilities Regulatory Authority spends week in Idaho with commission staff

Program is joint effort of NARUC, USAID and Power Africa

June 17, 2016 – Two officials from the Rwanda Utilities Regulatory Authority (RURA) were in Idaho during June to "job shadow" staff of the Idaho Public Utilities Commission.

Idaho was the first state to host an activity under a new partnership between the National Association of Regulatory Utility Commissioners (NARUC) and RURA, with the support of the U.S. Agency for International Development (USAID) and Power Africa.

NARUC's partnership with RURA enables regulators from the United States and Rwanda to share experience and best practices as well as to problem-solve to support more effective regulation.

"Our objective is to support RURA's efforts to improve its rate-setting practices so that Rwanda will be able to attract private investment in its power sector and, thus, increase access to electricity for its people," said Matt Elam, who heads up the Idaho commission's Technical Analysis Section.

Idaho Public Utilities Commission staff pictured with representatives from the Rwanda Utilities Regulatory Authority. Participants include, (front row from left) Bentley Erdwurm, Stacey Donohue, Aimee Nshimirimana (RURA), Alex Mudasingwa (RURA), Terri Carlock and Kathy Stockton; (middle row from left) Matt Elam, Yao Yin, Mark Rogers, Donn English and Gene Fadness; (back row from left) Mike Morrison, Mike Louis, Joe Terry and Johnathan Farley.

Visiting from Rwanda were Aimee Nshimirimana, a business plan analysis officer in the Economic Regulation Unit and Alex Mudasingwa, a technical compliance and monitoring officer in RURA's Electricity and Renewable Energy Unit.

Elam, who serves on NARUC's Staff Subcommittee for International Relations, said Idaho was selected partly because utilities here get most of their generation from hydroelectric resources as in Rwanda.

To date, only about 24 percent of Rwanda's households are connected to the electrical grid. The central-east African nation of 11.7 million people has an ambitious goal to increase connected households to 70 percent by the end of 2018. Rwanda has 190 MW of installed capacity, up from just 46 MW in 2004. Its forecasted generation for 2018 is about 563 MW, enough electricity to connect 70 percent of Rwandans to the electrical grid.

The job shadow is also designed to assist RURA in devising cost-reflective tariffs (rates) that will phase-out government subsidies to the nation's only electric utility by the end of fiscal year 2017-18.

Mudasingwa, who has a master's degree in engineering, and Nshimirimana, who has a master's degree in business administration, said they appreciated specifically learning about rate mechanisms in Idaho that encourage energy efficiency; that track changes in water, fuel costs and other variable expenses; and that allow ratepayers to share revenue with utilities once utility earnings reach a certain level. As in Idaho, Rwanda also has a number of independent power generators, so the Rwandan visitors were interested in the way the Idaho commission approves or denies power purchase agreements between utilities and independent generators.

"We appreciate very much the hospitality of the Idaho staff," Mudasingwa said. "It has been perfect, 100 percent."

"This has been a valuable experience for everyone," said Paul Kjellander, president of the Idaho Public Utilities Commission. "Our staff has learned a great deal from Alex and Aimee and we hope we have been as much help to them," Kjellander said. The PUC president expressed thanks to Elam, who was instrumental in bringing the Rwandan delegation to Idaho.

Idaho is a state member of NARUC, whose members include the state agencies that regulate utilities and carriers in the 50 states, District of Columbia, Puerto Rico and the Virgin Islands.

Power Africa is a U.S. government program seeking to attract needed investment in the power sector within sub-Saharan Africa. Its ultimate goal is to increase access to electricity by adding 30,000 MW of clean, efficient energy on the African continent.