Office of the Secretary
Service Date
August 20, 2015

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S PETITION TO MODIFY TERMS AND CONDITIONS OF PURPA PURCHASE AGREEMENTS	)	**CASE NO. IPC-E-15-01**
IN THE MATTER OF AVISTA CORPORATION'S PETITION TO MODIFY TERMS AND CONDITIONS OF PURPA PURCHASE AGREEMENTS	)	**CASE NO. AVU-E-15-01**
IN THE MATTER OF ROCKY MOUNTAIN POWER COMPANY'S PETITION TO MODIFY TERMS AND CONDITIONS OF PURPA PURCHASE AGREEMENTS	)	**CASE NO. PAC-E-15-03** **ORDER NO. 33357**

On January 30, 2015, Idaho Power Company filed a Petition asking the Commission to modify the length of prospective contracts under the Public Utility Regulatory Policies Act (PURPA). Specifically, the Company asked that the length of its new PURPA contracts for projects that exceed the published rate eligibility cap[1] be reduced from 20 years to two years. Avista Corporation and Rocky Mountain Power filed similar petitions and the three cases were consolidated into a single proceeding. Order No. 33250. The Commission granted temporary relief to the three petitioning utilities by reducing the length of PURPA contracts to five years while the Commission investigated the issue of contract length. Order Nos. 33222, 33250, 33253 (clarifying that interim relief applies only to new PURPA contracts that exceed the published rate eligibility cap), 33286 (denying petition to limit interim relief to only wind and solar PURPA contracts).

The Commission received almost 200 written comments from the public. The Commission held two public hearings and a two-day technical hearing. *See* Order No. 33253. After the record closed, the Commission received four timely petitions for intervenor funding. The matter being fully submitted, the Commission issues this Order reducing the length of IRP-based contracts from 20 years to two years.

[1] The "published rate" and published rate eligibility cap are explained *infra* in the Background Section I, B.

I. BACKGROUND

A. The Parties

The following parties petitioned for and were granted intervention:

J.R. Simplot Company
Idaho Conservation League
Intermountain Energy Partners (IEP)
Snake River Alliance (SRA)
Twin Falls Canal Company, North Side Canal Company, and
American Falls Reservoir District No. 2 (collectively, the Canals)
Idaho Irrigation Pumpers Association, Inc. (IIPA)
Clearwater Paper Corporation
Renewable Energy Coalition (REC)
Amalgamated Sugar Company
Micron Technology, Inc.
Sierra Club
AgPower DCD, LLC and AgPower Jerome, LLC
Ecoplexus, Inc.[2]

B. PURPA

Congress enacted PURPA in 1978 in response to a national energy crisis. "Its purpose was to lessen the country's dependence on foreign oil and to encourage the promotion and development of renewable energy technologies as alternatives to fossil fuels." Order No. 32580 at 3, *citing FERC v. Mississippi*, 456 U.S. 742, 745-46 (1982). Under the Act, the Federal Energy Regulatory Commission (FERC) prescribes rules for PURPA's implementation. 16 U.S.C. § 824a-3(a), (b). State regulatory authorities such as the Idaho Public Utilities Commission implement FERC regulations, but have "discretion in determining the manner in which the rules will be implemented." *Idaho Power Co. v. Idaho PUC*, 155 Idaho 780, 782, 316 P.3d 1278, 1280 (2013), *citing FERC v. Mississippi*, 456 U.S. at 751.

To encourage the development of renewable facilities, PURPA requires that electric utilities purchase the power produced by designated qualifying facilities (QFs). "This mandatory purchase requirement is often referred to as the 'must purchase' provision of PURPA." Order No. 32697 at 7; 16 U.S.C. § 824a-3(b); 18 C.F.R. § 292.303(a) (exceptions to the "must purchase" provision inapplicable in this case). Electric utilities are required to purchase power from QFs at rates equivalent to a utility's avoided cost and approved by this Commission. 16

[2] Ecoplexus filed its Petition to Intervene a month and a half after the deadline for intervention. The Commission granted Ecoplexus limited intervention in Order No. 33311.

U.S.C. § 824a-3; *Idaho Power*, 155 Idaho at 789, 316 P.3d at 1287. The purchase or "avoided cost" rate represents the "'incremental cost' to the purchasing utility of power which, but for the purchase of power from the QF, such utility would either generate itself or purchase from another source." Order No. 32580 at 3, *citing Rosebud Enterprises v. Idaho PUC*, 128 Idaho 624, 917 P.2d 781 (1996); 18 C.F.R. § 292.101(b)(6). The avoided cost rate must be "just and reasonable to the electric consumers . . . and in the public interest" and "shall not discriminate against [QFs]." 16 U.S.C. § 824a-3(b); 18 C.F.R. § 292.304. The Idaho Supreme Court has observed that the Commission has the authority to implement PURPA and that this grant of authority is broad. *Idaho Power*, 155 Idaho at 787, 316 P.3d at 1285; *Rosebud*, 128 Idaho at 627, 917 P.2d at 784; *A.W. Brown v. Idaho Power Company*, 121 Idaho 812, 814, 828 P.2d 841, 843 (1992).

This Commission has established two methods of calculating avoided cost, depending on the size of the QF project: (1) the surrogate avoided resource (SAR) methodology, and (2) the integrated resource plan (IRP) methodology. *See* Order No. 32697 at 7-8. The Commission uses the SAR methodology to establish what is commonly referred to as "published" or standard avoided cost rates. *Id.*; 18 C.F.R. § 292.304(c). Published rates are available for wind and solar QFs with a design capacity of up to 100 kilowatts (kW), and for QFs of all other resource types with a design capacity of up to 10 average megawatts (aMW). Order No. 32697 at 7-8. For QFs with design capacity above the published rate eligibility caps, avoided cost rates are "individually negotiated by the QF and the utility" using the IRP methodology based on the specific characteristics of the resource. Order Nos. 32697 at 2; 32176 at 1.

C. The Three Petitions

1. Idaho Power. In its Petition, Idaho Power asserted it has a total of 1,302 megawatts (MW) of PURPA QF projects under contract and "an additional 885 MW of PURPA solar capacity in the queue actively seeking PURPA Energy Sales Agreements to be on-line in 2016." Application at 2, 18; Exh. 2, p. 1 of 6. Idaho Power further asserted that if all these proposed solar projects come on-line, it would represent a "long-term financial obligation to customers of approximately $2.1 billion, in addition to the existing $2.6 billion obligation over the life of the Company's projects already on-line and operational." *Id.* at 3. At the technical hearing Idaho Power clarified that the amount of PURPA generation under contract had declined

from 1,302 MW to 1,161 MW but the amount of new solar projects in the queue had increased from 885 MW to 1,326 MW. Exh. 11, p. 4 of 4.

Given the possibility for large amounts of additional PURPA generation, Idaho Power contended that it is reaching a point at which the capacity of the proposed PURPA projects will exceed the Company's operational needs. *Id.* at 20. It asserted that this influx of PURPA generation is unnecessary given the Company's current surplus of generating capacity (aka capacity surplus) to 2021.[3] The Company maintained that continuation of 20-year PURPA contracts "places undue risk on customers at a time when Idaho Power has sufficient resources to meet customer demands." *Id.* at 2. According to Idaho Power, if it continues to acquire large amounts of unneeded, intermittent PURPA generation, it will increase its power supply costs and degrade its system reliability. *Id.* at 20-27.

The Company asserted that its must-take PURPA generation of 461 MW of solar and must-run hydro would exceed its total system load by about 33% of all hours. *Id.* at 26. Adding the proposed 885 MW of additional solar would exceed load by about 40% in all hours. *Id.* Idaho Power concluded that its continued obligation to acquire large amounts of PURPA generation under PURPA's must purchase provision without considering the Company's need for additional supply is unreasonable and contrary to the public interest. *Id.* at 27-34.

2. Rocky Mountain. On March 2, 2015, Rocky Mountain filed its Petition seeking a reduction in the length of its PURPA contracts. Rocky Mountain requested a permanent reduction in its PURPA contracts from 20 years to three years "to be consistent with the Company's hedging and trading policies and practices for non-PURPA energy contracts and [to be] more aligned with the [two-year] Integrated Resource Plan ("IRP") cycle." *Id.* at 3-4. Rocky Mountain asserted that it experienced a significant increase in proposed PURPA projects in the wake of Idaho Power's Petition. Petition at 2. These new requests combined with the large number of already executed contracts and proposed contracts prompted Rocky Mountain to file its Petition. Like Idaho Power, Rocky Mountain asserted that it has no need for generating resources in the next decade. *Id.* at 3.

Rocky Mountain claimed that within five days of the Commission granting interim relief to Idaho Power, Rocky Mountain received four requests for PURPA pricing totaling 130

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[3] At the hearing, the Company extended its capacity surplus estimate to 2024 based upon its 2015 Integrated Resource Plan (IRP). Tr. at 281; *see also* Case No. IPC-E-15-19.

MW "from QF developers who are located in Idaho Power's service territory but are now planning to obtain a transmission wheel to PacifiCorp in order to secure a more favorable 20-year contract with [PacifiCorp]." *Id.* at 4-5. With the addition of the four new projects, Rocky Mountain reported that it has 275.5 MW in proposed PURPA projects seeking Idaho contracts, in addition to the 189.6 MW of projects already approved by this Commission in Idaho. Thus, the Company has a total of 465.1 MW of existing and proposed PURPA contracts in Idaho. "This amount, at full nameplate capacity, would be enough to supply 108% of PacifiCorp's average Idaho retail load in 2014, and 275% of PacifiCorp's minimum Idaho retail load in 2014." *Id.* at 5.[4] Idaho's allocated share of PacifiCorp's executed PURPA contracts over the next ten years is $156 million, or about $15.6 million per year. *Id.* at 21.

In addition to reducing the length of its PURPA contracts, Rocky Mountain requested authority to modify its indicative (or incremental) pricing practice to reflect "all active QF projects in the pricing queue ahead of any newly proposed QF project that requests indicative avoided cost rates." *Id.* at 4. More specifically, the Company seeks relief from a prior Commission Order that required indicative rates be updated based upon "*signed* QF contracts." *Id.* at 32, 35 (emphasis original), *citing* Order No. 32697 at 22. Rocky Mountain asserted that this requirement and the dramatic increase in the number of proposed QF projects results in indicative pricing that does not reflect the most accurate and up-to-date avoided cost rates. If its indicative pricing were more robust, the Company maintained that its avoided cost rates would be $18 per MW hour (MWh) less on a 20-year levelized basis. *Id.* at 37.

3. Avista. Avista filed its Petition seeking relief on February 27, 2015, requesting the same interim and final relief that the Commission provides to Idaho Power or Rocky Mountain. Petition at 1. Avista observed that the Commission granted Idaho Power interim relief by limiting new PURPA contracts to five years during the pendency of its investigation. Order No. 33222. Avista expressed concern that without being afforded similar relief to the other two utilities, PURPA developers "may seek to sell such output to Avista." Petition at 3.

D. Granting Interim Relief

After reviewing Idaho Power's Petition, the Commission found that there was substantial evidence to grant the Company interim relief while the Commission initiated a formal

[4] PacifiCorp maintained that its average Idaho retail load in 2014 was 432 MW and the minimum Idaho retail load was 169 MW. Petition at 5 n.6.

investigation into the issue of contract length. Order No. 33222 at 4. More specifically, the Commission directed that IRP-based contracts be limited to five years in length until the Commission completes its formal investigation. Even before Idaho Power filed its Petition, the Commission expressed concern that in "less than four months' time, 13 QFs have contracted with Idaho Power for nearly 400 MW of solar generation – all expected to be on-line and producing power by the end of 2016."[5] Order No. 33222 at 3, *quoting* Order No. 33209 at 7. The Commission also noted within seven days of Idaho Power's Petition, the Commission had received four petitions to intervene and one of the prospective intervenors had already filed discovery. Order No. 33222 at 4. The Commission found that the influx of numerous "PURPA contracts could significantly and detrimentally impact customer rates and system reliability before this matter is fully resolved." *Id.* Consequently, the Commission found that interim relief limiting the length of IRP-based contracts pending resolution of the investigation is warranted. "[T]his interim measure will enable the Commission to address the PURPA implementation issues raised in this case, without having to simultaneously manage a continued tide of new PURPA cases." *Id.*

After Rocky Mountain and Avista filed their Petitions, the Commission also granted interim relief to the two utilities. Consistent with its prior Order Nos. 33222 and 33250, the Commission found there was substantial evidence to grant interim relief to the utilities for all IRP-based projects while the Commission investigated the issue of contract length. Order No. 33253. The Commission ordered that the three Petitions be consolidated into a single proceeding and set a deadline for intervention of March 27, 2015. Order No. 33250 at 8. The informal prehearing conference in the consolidated case was held on March 10, 2015. At the prehearing conference, the parties developed a schedule for processing the consolidated proceeding and discussed two petitions to clarify the scope of the case (see next Section). In Order No. 33253, the Commission adopted the procedural schedule recommended by the parties and set the technical hearing for June 29, 2015.

E. The Two Petitions to Clarify the Scope of the Case

1. <u>SAR vs. IRP Contracts</u>. In February 2015, Intermountain Energy Partners (IEP) and Renewable Energy Coalition (REC) each filed petitions seeking clarification regarding the scope of this docket. Briefly, IEP and REC sought to clarify whether the proposed reduction in

[5] The 13 projects were proposed by just three developers.

contract length is limited to those new QF projects that exceed the published rate eligibility cap (i.e., IRP-based methodology projects). At the prehearing conference on March 10, 2015, the parties to the case generally agreed the Commission should clarify its Order No. 33222 to indicate that interim relief of the five-year contract should apply only to new PURPA IRP-based contracts not SAR-based published rate contracts. In Order No. 33253, the Commission agreed and clarified that the scope of this proceeding addressed only the length of IRP-based PURPA contracts. Order No. 33253 at 4.

2. Limitation to Wind/Solar Contracts. On February 25, 2015, Clearwater Paper and J.R. Simplot Company filed a joint petition to also clarify the scope of interim relief granted to Idaho Power in Order No. 33222, and to limit the scope of the requested permanent relief. In their petition, Clearwater and Simplot sought to limit the interim relief of five-year PURPA contracts to only new "intermittent (solar and wind powered) projects." Joint Petition at 4. Idaho Power, Rocky Mountain and Commission Staff opposed the clarification proposed by Clearwater and Simplot.

In Order No. 33286, the Commission found no basis at this early stage of the proceeding to restrict the interim relief granted to the three utilities to "only wind and solar intermittent" resources. The Commission observed that the procedural schedule for the investigation is "expeditious enough" and that Clearwater and Simplot agreed to the expedited schedule. Order No. 33286 at 5.

II. PUBLIC COMMENTS

The Commission received nearly 200 written comments in this consolidated case. Of those, roughly 30 comments supported the petitions to shorten the PURPA contract length, and the rest opposed. At the public hearings, the Commission heard from 21 witnesses, all of whom opposed the petitions. These comments are discussed below.

A. Support for Petitions

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

Several large and small municipalities and Boise County also supported the petitions. These entities noted the importance of power reliability and affordability; some expressed that the utilities' requested relief was reasonable and balanced. These comments were echoed by a number of business development organizations and local chambers of commerce, which also expressed that the requested relief was good for development.

Finally, a handful of individuals supported the petitions. These individuals listed concerns for power reliability and maintaining low consumer electricity rates. Some expressed that the requested relief was "best for ratepayers" or in the "best interests of Idaho."

B. Opposition to Petitions

The City of Ketchum, the League of Women Voters, and a number of organizations filed comments opposing the petitions. These entities cited the need to promote renewable energy and distributed generation, and claimed that the requested permanent relief would eliminate solar development in Idaho. Ketchum also expressed concern that shortening PURPA contracts would eliminate community solar projects. Zahren Financial commented that shortening PURPA contracts as proposed by the utilities would impact its ability to invest in Idaho. Idaho Smart Growth asked that the utilities be required "to do all they can to continue to shift their power purchasing to renewable sources, and . . . to encourage them to embrace new models of clean energy production and distributed power."

A number of renewable energy developers also commented that shortening PURPA contracts would make it extremely difficult, if not impossible, for them to obtain the financing needed to develop their projects. Two developers proposed adopting an alternative to shortening 20-year PURPA contracts. They suggested the Commission maintain 20-year contracts, but allow the energy rate component of the contract to be adjusted annually after the first ten years of the contract. Pristine Sun and Renewable Northwest Comments.

Finally, more than 130 individuals sent written comments opposing the petitions, and 21 individuals opposed the petitions at public hearing. Most of those comments and public witnesses expressed the need to foster solar power development or "keep solar [development] viable." Many comments expressed the need to move away from coal and other fossil fuels toward clean energy. Several public witnesses noted that ratepayers were required to pay for the costs of transmission lines for 20 or more years, so requiring 20-year contracts for solar power is "only fair." A number of comments asked that the Commission "do what's right" for the future. And some comments expressed that utilities have not shown the need for their requested relief except to ensure the utilities increasing profits.

Commission Discussion: The Commission appreciates the considerable time and expense that participants dedicated to testifying in the public hearings, and the thoughtfulness evident in so many of the oral and written comments. The Commission recognizes that a large number of the public commenters encouraged the development of more solar and other renewable energy resources. Many of these same individuals also wanted the use of coal to be phased out. Finally, there were many concerns about retaining low and reasonable customer rates.

In direct response to the public concerns, we note that PURPA is not the only avenue to develop renewable resources. As Dr. Don Reading testified at our technical hearing, utilities have and will probably continue to develop non-PURPA renewable resources in the future through a variety of means. Tr. at 868-70. Indeed, as several witnesses pointed out in our hearing, the utilities have developed or purchased hundreds of MW of non-PURPA renewable as part of their generation portfolio. Tr. at 931, 111, 177-78. Moreover, acquiring more renewables while maintaining low rates is consistent with the State's 2012 Energy Plan.[6]

III. CONTRACT LENGTH

A. Do FERC Regulations Dictate the Length of Contracts?

The Commission first addresses whether the proposals to reduce the IRP-based PURPA contracts from 20 years are inconsistent with PURPA or FERC's regulations. ICL and Sierra Club's witness Adam Wenner testified that Idaho Power's proposal to reduce the length of contracts to two years is inconsistent with either FERC regulations or Idaho precedence for three reasons. First, he maintained that QF contracts were intended to provide both energy and capacity to the utility. PURPA and FERC's implementing regulations require that QFs be paid for capacity when a QF contract "enables the utility to replace new capacity with QF purchases." Tr. at 583. If contracts are limited to two years, he insisted that the capacity a QF could provide under its contract to the utility could not be "counted on to be available after two years. . . ." Tr.

[6] The Plan states that Idaho's "utilities need to have access to a broad variety of resources, <u>both conventional and renewable</u>, and nothing in this Energy Plan should be read as precluding a utility from investing in a particular resource." Section 6.2.2 at 115 (emphasis added).

at 587. In other words, a utility could not cancel or displace planned generation based on such a short two-year commitment.

Second, he maintained that short-term contracts impede a QF's ability to perfect a legally enforceable obligation (LEO). Under either a negotiated contract or a LEO,[7] a QF has an option to receive avoided cost rates either calculated at the time of delivery or at the time the obligation is incurred. 18 C.F.R. § 292.304(d)(2). He noted that in Order No. 69, FERC mentions that a QF may desire levelized payments (where a QF may wish to receive a greater percentage of the total purchase price during the beginning of the obligation than at the end of the contract term), if it enters into a "long term contract to provide energy or capacity to a utility." Tr. at 591, *citing* 45 Fed.Reg. 12,224 (Feb. 25, 1980).

Finally, Mr. Wenner also relied upon a 1984 Idaho Supreme Court case to support his opinion that QFs are entitled to a long-term contract. Tr. at 591-93, *citing Afton Energy v. Idaho Power Co. ("Afton I/III")*, 107 Idaho 781, 786, 693 P.2d 427, 432 (1984). In *Afton I/III*, he noted that the Supreme Court affirmed an Order of the Commission requiring Idaho Power to enter into a 35-year contract with a QF.

Clearwater and Simplot's witness Dr. Reading supported Mr. Wenner's opinion about the FERC regulations from an economic point of view. He testified that shortening the contracts to two, three, or five years will inhibit the QF from receiving future capacity payments due to the shortness of the contract. Tr. at 777-79. ICL/Sierra Club witness R. Thomas Beach and Snake River Alliance witness Ken Miller both opposed shortening IRP contracts. Tr. at 630; 734.

The three utilities and Commission Staff disputed Mr. Wenner's opinion that FERC regulations dictate a long-term PURPA contract. In particular, they point to his testimony where he acknowledged that FERC rules do not specify a number of years or other time period for PURPA contracts. Allphin, Tr. at 215-16; Clements, Tr. at 440-41, 513-15; Kalich, Tr. at 410-12; Wenner, Tr. at 589. Micron also argued in closing that PURPA does not mandate contract length. Tr. at 988-89. Rocky Mountain Power's witness Paul Clements explained that PURPA

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[7] There are two general methods by which a QF can provide power to a utility: (1) by entering into a signed contract with a utility; or (2) pursuant to a LEO. Order No. 32974 at 13, *citing* 18 C.F.R. § 292.304(d); *Power Resources Group v. PUC of Texas*, 422 F.3d 231, 237 (5th Cir. 2005); *Idaho Power*, 155 Idaho at 785, 316 P.3d at 1283. "FERC specifically adopted the concept of [a LEO] to prevent utilities from circumventing the 'must purchase' PURPA provision 'merely by refusing to enter into a contract with' a QF." Order No. 32974 at 13, *quoting Power Resources*, 422 F.3d at 238, *quoting* 45 Fed.Reg. 12,214, 12,224 (Feb. 25, 1980).

gives state regulatory agencies the discretion to establish the key terms and conditions of PURPA contracts. Tr. at 439-441.

Staff witness Rick Sterling testified that FERC regulations "are silent on [the issue of] contract length." Tr. at 902. He further maintained that FERC regulations only require utilities to provide five years of data to calculate the energy component of a utility's avoided cost rates and only ten years of data to calculate the capacity component of the avoided cost rates. *Id.* at 902-03. These forecasts "are much less than the 20-year contract." *Id.* at 903.

Mr. Clements and several other witnesses also noted that the length of PURPA contracts in Idaho has not been static. The Commission initially set contract terms for 35 years "to match the amortization period allowed for similar utility-owned facilities"; later shortened the contract length to 20 years; and shortened the contract length to five years in 1996 and 1997 "to align the QF contract timeframe with the utilities' acquisition strategies." Tr. at 441-43 (footnotes omitted); Grow, Tr. at 124-26. In 2002, the Commission raised the contract length back to 20 years. Tr. at 443; Sterling, Tr. at 897-98. Mr. Clements also noted that the Washington Commission sets standard avoided cost PURPA contracts in Washington for up to five years. *Id.* at 513.

Although Rocky Mountain recommended that the length of QF contracts be reduced to three years to coincide with the Company's hedging and planning process, Mr. Clements explained that limiting contracts to a three-year term

> does not mean that the [QF] project will only have a three-year life. Rocky Mountain Power will be required to purchase the power produced by the project as long as PURPA requirements exist and the project qualifies as a QF under PURPA. Limiting the term of the contract to three years simply means that the price Rocky Mountain Power and its customers will be required to pay to the QF will be subject to adjustment every three years and be more closely aligned with Rocky Mountain Power's current avoided cost.

Tr. at 511-12.

Commission Findings: As several parties observed, this Commission has set different contract lengths for PURPA contracts over the years. When PURPA was first implemented in Idaho, this Commission established a maximum contract term of 35 years, which it shortened to 20 years in 1987. Order Nos. 21018, 21630. The term was reduced to five years in 1996, and raised back to 20 years in 2002. Order Nos. 26576, 29029. Over the years the Commission has considered many factors (price risk, forecasting uncertainty, financing needs, amortization, plant durability) when establishing contract length. Order No. 32125. In February 2015, we granted interim and temporary relief in this matter, reducing the length for PURPA contracts from 20 years to five years, pending this final Order. Order No. 33222 at 4, 6.

As the Idaho Supreme Court recently stated in *Idaho Power Co. v. Idaho PUC*, a state commission "has discretion in determining the manner in which the [PURPA] rules will be implemented, and may comply by issuing regulations, by resolving disputes on a case-by-case basis, or by other actions reasonably designed to give effect to FERC's rules." 155 Idaho at 782, 316 P.3d at 1280, *citing FERC v. Mississippi*, 456 U.S. at 751. It "is up to the States, not [FERC] to determine the specific parameters of individual QF power purchase agreements. . . ." *Id.* at 786, 316 P.3d at 1284, *quoting Power Resources Group v. PUC of Texas*, 422 F.3d 231, 238 (5th Cir. 2005).

Based upon our review of federal court and state Supreme Court precedent, the testimony of the parties, PURPA, and FERC's implementing regulations, we find that PURPA and FERC regulations do not specify a mandatory length for PURPA contracts. As noted above, when PURPA was enacted, it was intended to encourage the development of renewable resources. Order Nos. 32697, 33250, 32125. PURPA "establishes a program of cooperative federalism that allows the States, within limits established by federal minimum standards, to enact and administer their own regulatory programs, structured to meet their own particular needs." *Idaho Power*, 155 Idaho at 782, 316 P.3d at 1280, *citing FERC v. Mississippi*, 456 U.S. at 767. Even Mr. Wenner acknowledged that FERC regulations do not dictate a specific number of years or establish a time period for PURPA contracts. Tr. at 589. It is not contested that PURPA, and its implementing regulations, are silent as to a specific contract length. Mr. Wenner's reliance on the *Afton I/III* case is misplaced. As our Supreme Court noted in the first sentence of its opinion, the basic issue presented in *Afton I/III* is whether the Commission "has authority to order an electric utility to purchase power from a [QF] for a fixed term according to avoided cost rates previously approved by the Commission." *Afton I/III*, 107 Idaho at 782, 693 P.2d at 428. Consequently, we find the issue of contract length is left to this Commission's discretion. *See Afton I/III*, 107 Idaho at 785-86, 693 P.2d at 431-32; *Idaho Power*, 155 Idaho at 782, 316 P.3d at 1280.

B. Are 20-Year Contracts Reasonable?

The three utilities and Commission Staff generally assert that 20-year contracts are no longer appropriate and should be shortened. Their witnesses offer several reasons to discontinue the 20-year contracts. Clearwater, Simplot, ICL, SRA and other parties urge the Commission to retain 20-year contracts. As an alternative to reducing the length of the 20-year contract, Clearwater/Simplot and ICL recommend the Commission consider "modifying" the 20-year IRP-based, fixed-rate contract by adjusting the energy component of the avoided cost rates after the first ten years. We explore those issues in greater detail below.

1. Idaho Power. Idaho Power's Senior Vice President, Lisa Grow, laid out several reasons why the Company believes that 20-year fixed-rate contracts are no longer reasonable. First, she asserted it was unreasonable for the Company to enter into long-term, fixed-rate contracts when the Company does not need additional generation. Tr. at 117, 119. She reported that the Company's peak-load for its system in 2014 was about 3,184 MW, while its minimum load was approximately 1,073 MW. Tr. at 107-08. In comparison, she noted that the Company's Exhibit 2 showed that Idaho Power had 1,297[8] MW of renewable, nameplate energy (both PURPA and non-PURPA) on its system or under contract, excluding the Company's 17 hydroelectric facilities.[9] Tr. at 109. This renewable generation consists of:

728 MW of wind (including 101 of non-PURPA wind)
320 MW of solar under contract[10]
35 MW of non-PURPA geothermal
214 MW of PURPA hydro and other renewable
1,297 MW renewable (nameplate capacity)

Tr. at 111, 177; Exh. 11, p. 2. Thus, Idaho Power's PURPA and non-PURPA renewable resources can be used to meet about 40% of its 2014 system peak-load and used to meet about 120% of its 2014 minimum system load.

Idaho Power witness Randy Allphin asserted that the Company has no need for additional generation "in the near term." Tr. at 206. He initially testified that the Company's recently released draft of its 2015 Integrated Resource Plan shows that the Company has a

[8] This figure is corrected to show the removal of 141 MW of approved solar contracts that were subsequently terminated for failing to post their required security deposits. Tr. at 376; *see* Exh. 11, p. 2.

[9] The Company's hydroelectric facilities total more than 1,700 MW of nameplate capacity.

[10] *Id.*

capacity surplus for 10 years, until 2025. *Id.* In his rebuttal testimony, he noted that the loss of the 141 MW of contracted solar generation caused the Company to refine its capacity deficiency estimate to July 2024.[11] Tr. at 281; Order No. 33343 at 2 (Case No. IPC-E-15-20).

When the Company has surplus capacity, it reduces the overall avoided cost rates paid to QFs. Avoided cost rates are typically comprised of a capacity component and an energy component. Ms. Grow explained that if a utility has surplus capacity at the time it enters into an IRP-based contract with a QF, then the QF does not receive capacity payments until the utility experiences a capacity deficiency. Tr. at 137. A utility's capacity status (e.g., surplus or deficient) is determined in each utility's Integrated Resource Plan.

In addition to the operating PURPA projects and those under contract, both Idaho Power witnesses observed at the time they filed their direct testimony, that the Company had received proposals for an additional 885 MW from solar developers. Tr. at 120, 177; Exh. 1-2. At hearing, the Company subsequently increased this amount of proposed solar projects from 885 to 1,326 MW. Exh. 11, p. 4 of 4. Ms. Grow repeated the concerns voiced by the Commission when it recently approved 400 MW of new solar projects. After recognizing the "must purchase" provision of PURPA, she quoted from the Order:

> Idaho Power's 2013 Integrated Resource Plan does not reflect that the utility is in need of energy to reliably serve its customers. And yet, <u>in less than four months time, 13 QFs have contracted with Idaho Power for nearly 400 MW of solar generation</u> – all expected to be on-line and producing power by the end of 2016. <u>The combined 20-year obligation of these 13 projects is approximately $1.2 billion</u>. . . . 100% of the costs of QF generation are passed onto ratepayers. . . .
>
> . . . QFs continue to request contracts with Idaho Power in significant enough numbers that we remain concerned about the Company's ability to balance the substantial amount of must-take intermittent generation and still reliably serve customers.

Tr. at 121-22 (citations omitted) (emphasis added).

Second, Ms. Grow maintained it was unreasonable and no longer in the public interest to maintain long-term, fixed-priced 20-year contracts while PURPA avoided cost rates continue to decrease. Tr. at 119. On cross-examination, Mr. Allphin agreed that the avoided cost rate for each new QF will decrease as "older" QFs add capacity to the system. Tr. at 260-

[11] *See supra* note 8.

61; Exh. 207. Ms. Grow also noted that the Company's Exhibit 7 shows that from 2004 to 2024 the Company's power supply expense increased approximately 575%. Tr. at 129. Allowing QF developers to obtain fixed prices over the long term causes electric rates to increase. Ms. Grow pointed out that the Company's Exhibit 10 shows that Idaho Power's average cost for PURPA generation since 2001 has always exceeded the Mid-Columbia (Mid-C) index price and is projected to continue to exceed the Mid-C price through 2032. Tr. at 129. She and Mr. Allphin testified that the average cost for PURPA purchases at $62.49 per MWh is greater than the average cost of coal ($22.79/MWh), the cost of gas ($33.57/MWh), non-PURPA purchases ($50.64/MWh), and "significantly greater than what is being sold [by the Company] as surplus sales at $22.41 per MWh." *Id.*; Allphin, Tr. at 191-92. This continued increase in net power supply costs adversely impacts ratepayers because these escalating costs are passed on to ratepayers.

Third, the Company's witnesses argued it makes little sense to require 20-year fixed-rate contracts for IRP-based PURPA projects when avoided cost rates are reset every two years under the IRP methodology. Ms. Grow noted that the IRP methodology is updated every two years to reflect current market conditions, customer growth, natural gas forecasts, and other conditions. Tr. at 127, 287. The IRP methodology is a good fit with the Company's risk management practices which limit power purchases and sales to 18-24 months. Tr. at 127-28, 287. She explained that before Idaho Power can acquire a long-term resource like a generating unit, there is a long and involved process for determining whether it is necessary and in the public interest for the Company to acquire a generating resource. *Id.* at 128. Typically, the Company assesses the need for such a resource; determines the type of resource necessary; examines how the operating characteristics of the resource fit into the Company's resource stack; requires that the resource be acquired through bidding and that the Company be able to dispatch the resource; seeks the approval of the Commission for a CPCN; and submits to a public process before the Commission. Then there is a subsequent case before the Commission permits a new generating plant to be placed into rate base. Tr. at 140; Allphin, Tr. at 196-200, 205. Purchasing the output of PURPA projects is not subject to these safeguards.

2. Rocky Mountain Power. Rocky Mountain Power's witness Paul Clements also recommended the Commission reduce the length of IRP-based contracts from 20 years. He maintained that PURPA was intended to encourage the development of renewable resources at

rates that: "(a) are just and reasonable to electric consumers, (b) do not discriminate against QFs, and (c) do not exceed 'the incremental cost to the electric utility of alternative electric energy.'" Tr. at 435, *citing* 16 U.S.C. § 824a-3(b). He noted that both this Commission and FERC have indicated that the avoided cost price structure "was to make ratepayers indifferent as to whether the utility used more traditional sources of power or the newly-encouraged [QF] alternatives." Tr. at 439, *quoting Southern California Edison Company*, 71 FERC ¶ 61,269 at p. 62,080 (1995), *overruled on other grounds*, *California PUC*, 133 FERC ¶ 61,059 (2010); Tr. at 435-37.

He requested that the Commission reduce Rocky Mountain's IRP-based contracts from 20 years to three years for several reasons. Tr. at 433. First, like Idaho Power, Mr. Clements testified that Rocky Mountain/PacifiCorp has a capacity surplus until 2028, and has no need for additional generation until that time. Tr. at 429. If all the proposed contracts were to become operational, the existing and proposed PURPA contracts would be enough to supply 108% of PacifiCorp's average retail load and 275% of its minimum retail load in Idaho in 2014. Tr. at 427.

Second, Mr. Clements insisted the 20-year, fixed-rate contracts violate the rate neutrality standard and act as a subsidy to the QF "because FERC generally requires a utility to lock in forecasted avoided cost rates for the entire contract term." Tr. at 441, 445 (*Regulations Implementing Section 210 of PURPA*, 45 Fed.Reg. 12,214, 12,224 (1980)). A proposed 20-year project can obtain a "fixed-price energy contract at the Company's projected avoided cost, without any economic considerations or pricing adjustment to account for the risk to utility customers from this unusual long-term transaction, or to the QF to account for the price certainty the QF enjoys from such a contract." Tr. at 445. Granting a 20-year contract with no adjustment to the price is something no other market participant enjoys and subjects ratepayers to unreasonable price risk. Tr. at 446-47.

He explained that the Company treats QF contracts as "system resources" and allocates these resources to the six states served by PacifiCorp. Idaho's share is approximately 6%. Tr. at 463. He stated that the expected system-wide payments to PURPA projects over the next ten years are $2.6 billion. In 2015, this equates to QF payments of $170.5 million, "with Idaho's allocated share at $10.2 million." Tr. at 463. If the avoided cost rates for these projects are priced incorrectly by just 10%, that would create an additional impact for Idaho ratepayers in 2015 of $1.0 million, and grow to a total of $15.5 million over the next 10 years. Tr. at 463.

Consequently, he stated it was imperative that avoided costs accurately reflect the Company's actual avoided costs during the term of the contract. Tr. at 464.

Third, Mr. Clements explained that the Company's proposal to reduce the 20-year IRP-based contract is intended to match the Company's risk management and hedging policies – the Company is generally limited to power purchase contracts of 36 months or less. Tr. at 469. For non-PURPA contracts, the Company enters into purchase transactions that exceed three years "only when there is a clearly identified long-term resource need in its IRP. Long-term resource needs are typically identified in the IRP only after lower-cost, lower-risk, short-term resource opportunities are exhausted." Tr. at 471. The Company avoids long-term, fixed-price energy contracts because they carry significant price risks. Tr. at 474-75. Shortening the contract term to three years will more closely align the IRP-based contract to the two-year IRP cycle, the three-year hedging plan, and the two to four year IRP action plan. Tr. at 479-80, 486.

Finally, Mr. Clements noted that PacifiCorp's cogeneration QFs (often referred to as combined heat and power – or CHP – QFs) do not need long-term contracts for financing purposes because these facilities are usually financed by their host businesses. Tr. at 476. He insisted that most cogeneration facilities "typically elect short-term contracts with PacifiCorp even when 20 year terms are available. In fact, most [cogeneration QFs] elect annual contracts that are renewed each year at the then-current avoided cost." Tr. at 476-77. These QFs prefer to take the spot or near-term avoided cost price to eliminate the price risk that comes from long-term fixed-price contracts. Tr. at 477. On cross-examination he stated that all of PacifiCorp's cogeneration PURPA contracts are short-term, "typically one year or less." Tr. at 541.

He concluded by observing that given the exponential increase in existing and proposed QF contracts for PacifiCorp,

> it is critical to quickly adjust pricing and contracting procedures now that problems with those procedures have been identified. The current Commission-approved PURPA contract length <u>puts retail customers at risk of harm due to significant and unnecessary exposure to long-term price risks, a level of risk the Commission would not accept in the context of a non-PURPA transaction</u>. The Company has no control over this price risk; it must purchase essentially an unlimited quantity of QF power under terms and conditions the Commission controls. Under PURPA, only the Commission can mitigate this price risk to customers.

Tr. at 489-93 (emphasis added). The shorter contract term is necessary to rebalance the must purchase provision that favors QFs with the ratepayer indifference standard.

3. Avista. If the Commission decides to shorten the length of IRP-based contracts for Idaho Power or Rocky Mountain, Avista requested the Commission to provide it with the same relief. Tr. at 404, 408. Its witness Clint Kalich requested that the utility be afforded similar relief "to ensure a level playing field across the Commission-regulated utilities." Tr. at 410. He asserted the Commission has the authority to shorten IRP-based contracts. Tr. at 412.

Mr. Kalich acknowledged that Avista has not received any proposed solar projects and that Avista has not been inundated with QF proposals like the other two utilities. Tr. at 414-15. He explained that different contract lengths among the utilities could cause an increase in filings at Avista if it had longer term contracts than the other two utilities. Tr. at 406-07. However, he did want Avista to maintain the option of having IRP-based contracts longer than five years if the terms of such contracts "are found by Avista and the [Commission] to be in the interest of utility customers. It is not possible to know every circumstance where a longer term agreement may be warranted." *Id.* at 410.

4. Staff. Commission Staff urged the Commission to reduce the 20-year term for IRP-based contracts to five years. Staff witness Rick Sterling testified that long-term contracts "based on forecasted rates create greater risks for customers because the rates in the later years are not reflective of avoided costs." Tr. at 902. He explained that one of the major factors in IRP-based contracts is the price of natural gas. "A long-term fixed price could possibly be accurate just once during its term – at the beginning of the contract when the rates are first established. The shorter the term of the contract, the more frequently prices can be adjusted to ensure they accurately represent the true value of the power. A shorter term contract helps to minimize the risk to ratepayers." Tr. at 905, 903. Because PURPA costs are passed on to customers through the Power Cost Adjustment (PCA) mechanisms, ratepayers are fully exposed to the risks if PURPA rates prove to be too high. Tr. at 906. Conversely, fuel costs for utility-owned resources are tracked annually and the rates adjusted annually.

Mr. Sterling further testified there were legitimate reasons why utilities were permitted to develop or acquire long-term generating assets but IRP-based PURPA resources should be restricted to two, three, or five-year contracts. Tr. at 915-16. He explained that when a utility acquires a resource it is usually a result of the Company's Integrated Resource Plan. As such, the utility resource is picked from a range of alternatives, is procured through a competitive process, and is contingent upon Commission approval in a public process. *Id.* Moreover, utility generating facilities have fuel costs that are annually adjusted and these facilities are dispatchable based upon the Company's load and generation requirements. Tr. at 917. On the other hand, PURPA projects are entitled to long-term contracts at fixed rates, acquired without consideration of need, undergo no competitive bidding, and their avoided cost rates are not based upon cost-based pricing. Tr. at 917, 925. He also noted that PURPA projects entirely circumvent the IRP planning process. Tr. at 918.

He also testified that the utilities have developed non-PURPA renewable resources. For example, Palouse Wind and Clearwater sell their power to Avista, and Elkhorn Wind sells to Idaho Power. Tr. at 931.

5. Idaho Irrigation Pumpers Association. The Irrigators offered the testimony of their witness Anthony Yankel, who supported Idaho Power's initial request to limit new IRP contracts to two years. Tr. at 301. Mr. Yankel explained that the flood of projects presents Idaho Power with a balancing problem of having to choose between curtailing its own must-run facilities, or its must-take PURPA contracts. Tr. at 305. He recommended the Commission reduce IRP contracts to two years as a "stop gap measure" while the Commission further refines the Company's models and modeling assumptions with actual Company operations. Tr. at 305. He also supported limiting new solar and wind projects to two years because of their intermittent nature. Tr. at 307.

6. Intermountain Energy Partners. IEP presented the testimony of its president, Mark van Gulik. He testified that the downward trend in avoided cost rates in Idaho means that fewer projects will be able to obtain financing and come on-line. Consequently, there is not an urgency for the Commission to shorten contract lengths. Tr. at 372.

As the developer of the Clark 1 through 4 solar projects, he explained the four projects were terminated when they were unable to make their required security deposits. Tr. at 376-77. He did not indicate that contract length contributed to the termination of these four projects totaling 141 MW of nameplate capacity. Because Idaho does not have attractive state tax incentives, he foresaw little likelihood for IRP-based projects to be able to attract the necessary capital if their contract terms were less than 15 years. Tr. at 386.

7. ICL/Sierra Club. ICL's and Sierra Club's second witness was Thomas Beach who urged the Commission to retain the 20-year IRP-based contract. Tr. at 630-52. He indicated that current indicative pricing for levelized avoided cost rates continues to decline by "more than 50% below the $60 to $64 per MW range of avoided costs for the recently-approved 20-year solar contracts." Tr. at 630-31; Table 3 at Tr. 642 (footnote omitted). Reducing the length of 20-year long-term contracts as avoided cost rates continue to decline, "appears likely to make uneconomic QFs that could be developed at avoided cost prices with a long-term agreement." Tr. at 631. He noted that when the Commission reduced IRP-based contracts to five years between 1996 and 2001, only one PURPA contract was executed during that time with Idaho Power. Tr. at 632.

He maintained that Idaho Power's IRP methodology is generally working well as indicated in the decline in avoided cost rates for solar contracts as shown in Table 3 of his testimony. Tr. at 642. Of the 48 projects totaling 885 MW, only 14 have progressed far enough to receive indicative pricing, and of those, only one has requested a contract. Tr. at 644. "As more solar capacity has been added, the avoided cost price has fallen based on Idaho Power's capacity position and future needs." Tr. at 644. And, as "avoided cost prices fall, fewer projects will be built." *Id.*

8. Clearwater Paper and J.R. Simplot Company. Clearwater and Simplot presented the testimony of their witness Dr. Reading who opposed efforts to reduce the length of the IRP-based contracts from 20 years. Dr. Reading insisted that conditions have not changed since the Commission last decided to resume 20-year contracts in 2012. In particular, he argued that the only condition that may have changed since 2012 was that the utilities' avoided costs may have decreased but that does not mean the term of the contract should be reduced. Tr. at 785-86. He argued that reducing the contract length to five years or less will not encourage the development of renewable resources. Tr. at 778-79. He insisted that reducing the contract as proposed by the utilities and Staff will make it impossible for a QF to obtain financing for their projects. *Id.* He noted that the last time the Commission reduced PURPA contracts to five years, "only one PURPA contract was signed in Idaho with the shortened contract length." *Id.* at 780.

He maintained it would be unreasonable to limit IRP-based contracts to five years when the recovery of investment for utility-owned resources is much longer, and in some cases up to 50 years. He argued that PURPA resources should be placed "on an equal footing with utility-owned resources . . . [and] should receive longer-term contracts." Tr. at 781.

He next compared the cost of PURPA projects with the cost of Idaho Power's generating resources. He determined that the price per MWh of Idaho Power's PURPA projects compare favorably to the Company's facilities. *See* Chart No. 1 at Tr. at 793. In preparing his chart and analysis, he acknowledged that he removed Idaho Power's hydro facilities ("the Company's lowest cost resource with the depreciated rate base and very low variable running cost"). Tr. at 794. He removed these lower cost facilities from his analysis because streamflow conditions vary from year-to-year and the cost of relicensing Idaho Power's largest hydro complex (Hells Canyon) is not yet known. Tr. at 794-95.

He also testified that cogeneration projects are unique from other types of PURPA projects and are deserving of continued access to long-term IRP contracts. Tr. at 819-23. He argued that Idaho Power's Petition primarily points to the problem of oversupply from "intermittent and relatively unpredictable PURPA output from wind and solar projects." Tr. at 823. Consequently, he suggested that any reduction in the length of IRP contracts not apply to cogeneration projects.

9. Snake River Alliance. Ken Miller testified on behalf of SRA. He opposed reducing the 20-year IRP-based contract length and expressed concern that development of utility-scale solar will be impaired. Tr. at 734. As the Environmental Protection Agency (EPA) finishes its Clean Power Plan,[12] Idaho's utilities will have greater need for solar as they reduce their reliance on their coal-fired generating facilities. Tr. at 735-36. Given the projected reductions in coal-fired generation, the shrinkage in the utility's projected overcapacity will likely prompt utilities to need more solar generation. Tr. at 739-40.

Commission Findings: We recognize that PURPA was intended to encourage the development of renewable resources. Order Nos. 32580 at 3; 32697, *citing FERC v. Mississippi*, 456 U.S. at 745-46. Indeed, this Commission has a long history of encouraging PURPA projects and renewable energy development in Idaho. Order No. 32697 at 14. As shown in Idaho Power's Exhibits 1 and 11, the growth of renewable generation started modestly. Idaho Power accumulated less than 200 MW in 25 years (roughly from 1982-2007). Since 2007, PURPA generation has increased dramatically, and for Idaho Power in particular, its PURPA generation

[12] EPA issued its Clean Power Plan on August 3, 2015.

under contract has grown to about 1,161 MW – nearly a six-fold increase. Exh. 11. In just three months (November 2014 through January 2015), the Commission approved 13 solar contracts totaling more than 400 MW.

To encourage the development of renewables, PURPA and FERC regulations lay out several standards, two of which are paramount in this case. First, PURPA requires that electric utilities "must purchase" the power produced by QFs. QFs are paid based on costs that the utility avoids. Order No. 32697 at 7; 16 U.S.C. § 824a-3(b); 18 C.F.R. § 292.303(a). A utility's avoided cost represents the incremental cost to the purchasing utility of power which, but for the purchase of power from the QF, such utility would either generate itself or purchase from another source. Order No. 32580 at 3, *citing Rosebud*, 128 Idaho at 627, 917 P.2d at 784. PURPA and FERC regulations require that the avoided cost rate must be "just and reasonable to electric consumers of the utility and in the public interest, and shall not discriminate against [QFs]." Order No. 32697 at 16, *citing* 16 U.S.C. § 824a-3(b); 18 C.F.R. § 292.304(a)(1) (internal punctuation omitted).

Second, FERC regulations allow a QF to choose to have the avoided cost rates for the purchase of its power calculated in one of two ways: (1) at the time of delivery; or (2) at the time it enters into the contract/obligation for the delivery of power. 18 C.F.R. § 292.304(d); 45 Fed.Reg. at 12,224. In Idaho, most IRP projects choose to have the avoided cost rates calculated or "fixed" at the time the contract obligation is incurred with their actual operation/on-line dates one to two years later. Thus, the rates are fixed for the duration of the 20-year contract.

The Idaho Supreme Court has recognized that PURPA contracts represent a "special type of contract." *Afton I/III*, 107 Idaho at 793, 693 P.2d at 439; *Afton Energy v. Idaho Power Co. ("Afton V")*, 114 Idaho 852, 854, 761 P.2d 1204, 1206 (1988); Order No. 32802 at 17. We have also said in prior Orders, PURPA contracts are special because "federal law compels utilities to purchase power without arms-length bargaining and without regard to whether the utility needs the power. . . . Even if QF power replaces power the utility would otherwise generate, ratepayers are ultimately paying for both the capital assets of the utility's base load generating plant in rates and the QF power." Order No. 32802 at 17-18.

Returning to this case, there seems to be general agreement among the parties that as more PURPA power is offered to the utility, the avoided cost rates for IRP projects will decline. Tr. at 260-61; 372; 630-31; 642. It is therefore axiomatic that long-term avoided cost rates determined at the time parties enter into their contract will "overestimate" future avoided costs collected from the utilities' ratepayers. Because of the 20-year term of the current IRP-based contracts, this "overestimation" will become more significant over the duration of the contract.

When FERC issued its initial PURPA regulations, it acknowledged that avoided costs calculated when the parties enter into the contract might result in future avoided costs over the term of the contract being greater than actual avoided costs at the time of delivery. FERC recognized that in such cases a utility "would subsidize the [QF] at the expense of the utility's other ratepayers." 45 Fed.Reg. at 12,224; Tr. at 775-77. In other cases, FERC postulated that the avoided costs calculated at the time of delivery "will turn out to be lower than the avoided cost at the time of [contract]." *Id.* Thus, FERC believed "that, in the long run, 'overestimations' and 'underestimations' of avoided costs will balance out." *Id.*

Based upon our record, we find that 20-year contracts exacerbate overestimations to a point that avoided cost rates over the long-term period are unreasonable and inconsistent with the public interest. We find shorter contracts reasonable and consistent with federal and state law for multiple reasons. First, shorter contracts have the potential to benefit both the QF and the ratepayer. By adjusting avoided cost rates more frequently, avoided costs become a truer reflection of the actual costs avoided by the utility <u>and</u> allow QFs and ratepayers to benefit from normal fluctuations in the market.

Second, shorter contract lengths do not ultimately prevent a QF from selling energy to a utility over the course of 20 years – or longer. PURPA's "must purchase" provision requires the utility to continue to purchase the QF's power. As long as projects continue to offer power to utilities, utilities must continue to purchase such power under PURPA. A shorter contract length merely functions as a reset for calculation of the avoided costs in order to maintain a more accurate reflection of the actual costs avoided by the utility over the long term. Our approach is not dissimilar to that suggested by witnesses Reading and Beach discussed below.

As an alternative to discontinuing the 20-year contract, Dr. Reading and Mr. Beach suggested similar but different alternatives. Dr. Reading suggested that the Commission could retain the 20-year contract but adjust the energy component in each of the last 10 years of the contract. Tr. at 842. Mr. Beach suggested that the Commission could make a single adjustment in the 11th year of a 20-year contract. He explained that the 20-year contract could be "repriced after the first 10 years . . . [but] the indicative energy price for Years 11-20 would continue to be fixed." Tr. at 701-702.

While we appreciate the concessions evident in these proposed alternatives, we find the recommendations unpersuasive. An adjustable rate contract runs the risk of violating FERC regulations that mandate a "fixed rate" at the time of contracting. 18 C.F.R. § 292.304(d)(2)(ii); Tr. at 213-15. Moreover, the same result can be accomplished through successive short-term contracts. Tr. at 214; 515-17.

Third, we further find the arguments asking the Commission to treat QFs similarly with utility resources unavailing. As is evident upon review of the extensive record (explained by several witnesses), QFs differ from utility resources in several significant and material ways. A utility "cannot be compensated by its customers for energy produced from a generating facility until the utility establishes the need for such new generation" by requesting a Certificate of Public Convenience and Necessity (CPCN). *Idaho Code* §§ 61-526, 61-541. Order No. 32697 at 15-16. In contrast, PURPA requires the utility to purchase QF power whether the power is needed or not. Next, a utility-authorized resource is typically subject to competitive bidding, cost scrutiny, and oftentimes has dispatch characteristics different than most QFs. Moreover, the fuel component for utility generating plants is adjusted annually, but is fixed for the duration of fuel-based, long-term QF contracts. QFs are entitled to receive full avoided cost rates. However, the calculation of avoided costs is entirely unrelated to what it costs a PURPA project to be developed. Tr. at 290; *see also* Tr. at 196-200, 205, 507-510, 924-26. The utilities also demonstrated that avoided cost rates exceed the Mid-C index price and their average costs of either generating or purchasing power. Tr. at 129, 191-92, 477-80.

Finally, if the goal of PURPA was to "encourage" the development of renewable resources, Idaho has made significant advancements toward that goal. Both Idaho Power and PacifiCorp presented persuasive evidence of capacity surpluses. These two utilities have demonstrated that their supply of PURPA and non-PURPA power exceeds their current average loads. Tr. at 111, 117, 931. The abundance of PURPA generation extends the utilities' capacity surpluses to 2024 for Idaho Power and 2028 for PacifiCorp.

A change in the length of IRP-based contracts is not intended to be punitive to QFs. For several years this Commission has been adjusting terms and conditions of PURPA contracts in order to establish avoided cost rates that are just and reasonable to electric consumers, in the public interest, and not discriminatory against QFs. We find that a change in contract length aligns with the intent of PURPA, is consistent with FERC regulations and achieves an appropriate balance between the competing interests of protecting ratepayers and developing QF generation.

Based upon our review of the evidence, we find that the length of new IRP-based contracts should be set at two years for all three utilities. There are several reasons to support our finding. First, given the two-year planning cycle for the Integrated Resource Planning process, we find it is reasonable to set the length of IRP contracts at two years. Matching IRP contracts to the IRP planning cycle provides more accurate IRP avoided costs, reduces price risk, and provides more forecast certainty. Tr. at 486, 127-28, 287, 902-05, 915-17. Further, the two-year cycle better matches the utilities' hedging and risk management practices.

We are not persuaded that setting IRP-based contracts to two years will result in a substantial decline of renewable resources. The utilities all have ample amounts of PURPA power on their systems; additional renewable generation is in the queue; SAR-based contracts are still 20 years; and the "must purchase" provision will still require utilities to purchase all renewable generation offered by QFs. Moreover, PURPA is not the only means through which a utility can obtain and/or utilize renewable resources. All the utilities have acquired non-PURPA renewable resources and/or shorter term cogeneration projects. As PacifiCorp's Mr. Clements testified, all of PacifiCorp's cogeneration contracts are for a period of one year. Tr. at 476-77. And we note that over the years, neither Clearwater nor Simplot have chosen QF contracts of 20 years. Tr. at 858. In fact, Clearwater's most recent cogeneration agreement was not a PURPA contract.

In reducing IRP-based contracts to two years, we find that a clarification in calculating the capacity deficiency of the IRP-based projects is warranted. As we have said in previous Orders, a utility is to begin payments to a QF for capacity "at such time as the utility becomes capacity deficient. . . . By including a capacity payment only when the utility becomes capacity deficient, the utilities are paying rates that are a more accurate reflection of a true avoided cost for the QF power." Order No. 32697 at 21. We recognize that a new two-year contract would be unlikely to reach a capacity deficiency date. Therefore, we find it reasonable for utilities to establish capacity deficiency at the time the initial IRP-based contract is signed. As long as the QF renews its contract and continuously sells power to the utility, the QF is entitled to capacity based on the capacity deficiency date established at the time of its initial contract. For example, if the QF comes on-line in 2017 and the utility is capacity deficient in 2020, the QF would be eligible for capacity payments in the second year of its second contract and thereafter if in continuous operation. This adjustment recognizes that in ensuing contract periods, the QF is considered part of the utility's resource stack and will be contributing to reducing the utility's need for capacity. This mitigates the concern that short-term contracts will not contribute to the avoidance of utility capacity/generation.

We further find that on a case-by-case basis, there may be justification for IRP-based contracts in excess of two years. This is consistent with our prior Orders. Order Nos. 27213; 26576 at 6-7; Order No. 32697 at 25. In those instances when the utility and the project developer believe that a longer term is justified, utilities are directed as part of their standard negotiation process to fairly evaluate such requests. The Commission will consider those contract terms when they are submitted for approval.

C. Indicative or Incremental Pricing

As part of its Petition, Rocky Mountain asked that the Commission allow it to change its "indicative" pricing practice in the IRP methodology so that it may provide more accurate avoided cost rates to proposed QF projects. Petition at 4. Indicative or "incremental" prices are the preliminary estimates of IRP-based avoided cost rates and are the incremental cost a utility would otherwise incur for the capacity and energy that the QF proposes to sell to the utility. Yin, Tr. at 876. Incremental prices serve as the starting point for negotiations between QFs and a utility. *Id.*

Rocky Mountain seeks relief from a prior Commission Order in Case No. GNR-E-11-03 that generally directed that incremental pricing be updated after "the QF and utility <u>have entered into a signed contract</u> for the sale and purchase of QF power." Order No. 32697 at 22 (emphasis added). In other words, the utility's calculation of an updated incremental price is based upon signed contracts, not all projects seeking to sell power to a utility.

1. <u>Rocky Mountain's Proposal</u>. In its Petition, Rocky Mountain asked for approval to arrange proposed QF projects in a queue and provide those QFs with incremental pricing as part of the IRP negotiation process. Rocky Mountain Petition at 37-38. The avoided cost prices/rates would be based on each QF's place in the queue, and would be calculated using that QF's proposed power and that of all earlier-queued projects. *Id.* Rocky Mountain asserted that

the "drastic increase in the number of QF requests received in both Idaho and over [Rocky Mountain/PacifiCorp's] six-state system in recent years" results in "artificially inflated avoided cost pricing." *Id.*

Rocky Mountain's witness Brian Dickman explained:

> Avoided costs for the first QF in [a] queue are based on displacement of the highest cost resources on [Rocky Mountain's] system. Each successive QF should displace lower and lower cost resources, resulting in lower avoided costs.

Dickman, Tr. at 560. The price of proposed power from queued projects is "not captured if the recognition of new long-term commitments is limited to signed contracts." *Id.* at 564. If a utility cannot update its avoided cost pricing to reflect the price for proposed power from the queue, the queued projects all receive avoided cost rates or prices that are not up-to-date and too high.

Mr. Dickman also testified that it would be "prohibitively time consuming and problematic from a contract negotiation standpoint," to recalculate prices for new QF projects as other proposed QFs sign contracts. *Id.* at 572. He suggested the Commission should modify the incremental pricing practice in the IRP methodology "to account for proposed QF projects on [Rocky Mountain's] system prior to the next Idaho QF requesting indicative prices." *Id.* at 574.

Clearwater and Simplot's witness Dr. Reading supported the proposal. Tr. at 831. No party opposed Rocky Mountain's incremental pricing request.

2. <u>Staff Support</u>. Staff recommended the Commission adopt Rocky Mountain's proposal to update its incremental avoided cost pricing. Staff witness Dr. Yao Yin testified that under the incremental pricing practice approved per Order No. 32697, "proposed projects are not placed in a queue but are instead treated for pricing purposes as if they are all the first project to receive the next [incremental price]." Tr. at 877. Although this practice "may result in accurate avoided cost rates," Dr. Yin observed that "it can be very difficult to recalculate rates for proposed projects in a timely manner when there are many projects seeking indicative prices at the same time." *Id.* at 877-78. "In addition, a QF may not want to renegotiate the new updated rates, because the new indicative prices may be lower than the original ones." *Id.* at 878.

Dr. Yin noted that current "PURPA project sizes are much larger, both individually and cumulatively, and multiple projects frequently seek indicative prices at the same time." *Id.* at 879. The pricing practice proposed by Rocky Mountain "would offer more accurate indicative prices to QFs by putting all the proposed projects into a queue based on the times they request indicative prices." *Id.*

She explained that Idaho Power and Avista have tariff schedules (Sch. 73 and 62, respectively) that "specify the information a project needs to submit before requesting indicative prices," and that "specify timeline milestones for QFs to meet as projects and negotiations progress." *Id.* at 876, 881. Dr. Yin recommended that Rocky Mountain be directed to file a similar schedule in Idaho "so that QF projects can have a better idea of the procedures for requesting indicative prices in Idaho," and that would "lay out the PURPA negotiating process and prevent projects from prematurely requesting indicative pricing." *Id.* at 876-77, 882. She further recommended that Rocky Mountain develop "specific criteria . . . for management of the queue, such as rules for QF entry, re-positioning, and removal from the queue." *Id.* at 882. Finally, she recommended that the Commission "discontinue the 'signed contract' requirement in Order No. 32697 for purposes of giving indicative pricing to IRP-based projects." *Id.* at 882-83.

Commission Findings: The Commission finds that the "signed contract" language in Order No. 32697 did not achieve its intended result. When developers flood the utilities with many proposed projects in a short period of time, the "signed contract" requirement yields inaccurate avoided costs. The result is artificially inflated pricing.

We find that creation of a queue to track the order in which QF projects have entered negotiations with a utility, so that incremental pricing can be calculated to reflect the actual impacts of each project is reasonable and appropriate. Consequently, we eliminate the "signed contract" requirement of Order No. 32697 and allow utilities to update their incremental pricing for QFs in their PURPA queue. *Idaho Code* § 61-624. Such a process will improve the accuracy of proposed prices, and improve the predictability of the process to both the utilities and the QFs. We also direct Rocky Mountain to file a tariff schedule, like those of Idaho Power and Avista, which outlines its PURPA negotiating process. The schedule should include specific criteria for management of the queue to eliminate uncertainty and to facilitate negotiations between Rocky Mountain and QFs.

IV. INTERVENOR FUNDING

A. Funding Standards

Intervenor funding is available pursuant to *Idaho Code* § 61-617A and Commission Rules 161 through 165. Section 61-617A(1) declares that it is "the policy of [Idaho] to encourage participation at all stages of all proceedings before this commission so that all affected customers receive full and fair representation in those proceedings." *Idaho Code* § 61-617A(2). The statute authorizes the Commission to order any regulated utility with intrastate annual revenues exceeding $3.5 million to pay all or a portion of the costs of one or more parties. Intervenor funding costs include: legal fees, witness fees, transportation and other expenses so long as the total funding for all intervening parties does not exceed $40,000 in any proceeding. *Idaho Code* § 61-617A(2). The Commission must consider the following factors when deciding whether to award intervenor funding:

(1) That the participation of the intervenor has materially contributed to the Commission's decision;

(2) That the costs of intervention are reasonable in amount and would be a significant financial hardship for the intervenor;

(3) The recommendation made by the intervenor differs materially from the testimony and exhibits of the Commission Staff; and

(4) The testimony and participation of the intervenor addressed issues of concern to the general body of customers.

Idaho Code § 61-617A(2). To obtain an award of intervenor funding, an intervenor must comply with Commission Procedural Rules 161-165. The petition must contain an itemized list of expenses broken down into categories; a statement explaining why the costs constitute a significant financial hardship; and a statement showing the class of customer on whose behalf the intervenor participated. Rule 162, IDAPA 31.01.01.162.

B. The Intervenor Funding Requests

As set out in greater detail below, the Commission received four petitions for intervenor funding, requesting a total of about $58,000. It is undisputed that each of the three electric utilities in this case has intrastate revenues that exceed $3.5 million.

1. Idaho Conservation League. On July 1, 2015, ICL filed a Petition for Intervenor Funding seeking recovery of $9,652.50 in expenses. ICL is a non-profit organization and claims that its members and supporters are ratepayers of all three electric utilities. Petition at 3. ICL maintained that it receives financial support solely through charitable donations from its members and foundations. *Id.* It asserted that it actively strived to reduce its expenditures by not seeking any travel costs, reproduction fees, and that the services of its witness, Mr. Wenner, were

provided pro bono. Moreover, ICL requested only 60% of its other witness's hourly rate. ICL submitted that its witnesses' testimony was materially different from that testimony offered by the Commission Staff. In particular, ICL argued that the Commission should maintain the 20-year fixed-price contracts for IRP-based projects. Petition at 5. In summary, ICL requested recovery of its legal fees in the amount of $4,050 and witness fees in the amount of $5,602.50.

2. Renewable Energy Coalition. On July 9, 2015, REC filed its Petition for Intervenor Funding seeking an award of $8,751.50.[13] REC members represent small hydro power producers that either have or may seek PURPA contracts with Idaho's electric utilities. Petition at 3. REC members imposed a special assessment against themselves to support their intervention in this case. Petition at 4. However, costs for intervenors in this proceeding exceeded the assessment. *Id.* In addition, REC has not sought recovery of all of its legal fees nor the costs of its primary witness, Mr. Lowe, in this case. REC declared that its testimony also differed from that offered by Commission Staff. It maintains that it is the only party that recommended the Commission should broadly investigate the issues raised by utilities when balancing the interest of ratepayers and small QFs. In summary, REC sought to recover its legal fees in the amount of $7,936.50 and its travel expenses in the amount of $815.

3. Snake River Alliance. On July 9, 2015, SRA filed its Petition for Intervenor Funding seeking $5,800 "rounded down for convenience." Petition at 3. SRA characterizes itself as a small, non-profit organization "supported by charitable contributions from individuals, families, and foundations." *Id.* Its participation in this case was "necessary to provide a voice for its members and ratepayers that 'face significant economic and environmental risks associated with the utilities' coal fleet [by] pursuit of clean and renewable alternatives to coal and large hydropower." *Id.* SRA opposed the utilities' and Staff's proposals to reduce the length of 20-year PURPA contracts but supported adjusting the energy component of avoided cost rates at the 10-year mark. *Id.* at 2.

SRA only requested recovery of its legal fees and did not seek reimbursement for its witness and Energy Director, Ken Miller.

4. Irrigation Pumpers Association. On July 10, 2015, the Irrigators filed their Petition for Intervenor Funding seeking a total of $33,733.72. The Irrigators sought recovery of

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[13] In its Petition, REC sought an award of $8,800 (Petition at 2; Exh. A) but the expenses listed in its Exhibit A total $8,751.50.

their legal fees ($7,500), witness fees ($24,450), and travel expenses ($1,783.72). Petition at Exh. A. The Irrigators are a non-profit corporation representing farmers' interests in electric utility matters in southern Idaho. Petition at 3. The Irrigators rely solely on dues and contributions voluntarily paid by its due-paying members. They only have one part-time paid contractor who shares office space in Boise. The Irrigators' position was materially different than that addressed by Commission Staff or other parties. They maintained that Idaho Power was operating its system inconsistently with the assumptions in Idaho Power's avoided cost models. *Id.* at 3. They urged the Commission to reduce the length of contracts while the Commission refines the avoided cost methodology.

Commission Findings: The Commission finds that the requests for intervenor funding satisfy the intervenor funding requirements. Each intervenor participated in the case and materially contributed to the examination of the issues and the Commission's decision. As set out above, each intervenor's petition materially differed from Staff's position. We further find that the lack of intervenor funding would be a significant financial hardship to these intervenors and that their costs of intervention, for the most part, are reasonable. However, the total amount requested exceeds that which is available by statute. Therefore, we find it fair, just and reasonable to award the intervenors the following funding amounts totaling $40,000.

INTERVENOR	AWARD
ICL	$ 8,635
REC	$ 8,314
SRA	$ 5,266
IIPA	$17,785
Total	$40,000

The intervenor funding award shall be recovered from Avista, Idaho Power and Rocky Mountain Power based on a proportional share of the total number of Idaho customers served by each utility. *See* Order No. 32697. The funding awards to ICL, REC, and SRA shall be chargeable to the electric residential customer class. The Irrigators' costs shall be chargeable to the irrigation customer class of the three utilities. *Idaho Code* § 61-617A(3).

ULTIMATE FINDINGS AND CONCLUSIONS

The Commission has jurisdiction over this matter pursuant to the authority and power granted it under Title 61 of the Idaho Code and the Public Utility Regulatory Policies Act (PURPA). The Commission has authority to set avoided cost rates, to order electric utilities to enter into fixed-term obligation for the purchase of energy and capacity from QFs, and to set the term of PURPA contracts. The Commission is also empowered to resolve disputes between utilities and QFs and to approve PURPA contracts.

PURPA and FERC regulations direct not only that the rates for purchases not discriminate against QFs, but also that avoided cost rates be just and reasonable to the utility's ratepayers and in the public interest. 18 C.F.R. § 292.304(a)(1). This Order shortens the length of IRP-based PURPA contracts in order to maintain a more accurate avoided cost. However, the "must purchase" obligation of PURPA will allow QFs to continually renew their contracts. Moreover, QFs will continue to be compensated for capacity calculated at the time they initially enter their IRP-based contract. Also, proposed IRP-based contracts that are longer than two years will be evaluated on a case-by-case basis. This Order strikes a balance between just and reasonable rates for ratepayers, the public interest and the interests of QFs, as is mandated by PURPA and FERC regulations.

O R D E R

IT IS HEREBY ORDERED that Idaho Power's Petition to reduce the length of its IRP-based PURPA contracts from 20 years to two years is granted.

IT IS FURTHER ORDERED that Rocky Mountain Power's Petition to reduce the length of its IRP-based PURPA contracts from 20 years to three years is granted in part and modified in part. Rocky Mountain shall reduce the length of its IRP-based PURPA contracts to two years.

IT IS FURTHER ORDERED that Avista's Petition to reduce the length of its IRP-based PURPA contracts to two years is granted as set out above.

IT IS FURTHER ORDERED that Rocky Mountain Power's request to change its indicative (incremental) pricing practices is granted as set out above. The requirement that utilities update their indicative pricing practices based on signed contracts is rescinded. *Idaho Code* § 61-624. PacifiCorp shall file a schedule setting out its PURPA negotiating practices and queue management.

IT IS FURTHER ORDERED that the capacity components for IRP-based QF contracts shall be calculated for all new IRP contracts to begin at the time the QF first enters its two-year contract provided such contract is continued in the future.

IT IS FURTHER ORDERED that Avista, Idaho Power, and Rocky Mountain Power may enter IRP-based QF contracts in excess of two years on a case-by-case basis with appropriate justification.

IT IS FURTHER ORDERED that the four Petitions for Intervenor Funding are granted as set out in greater detail above. The utilities are directed to remit their respective amounts to the four intervenors within 28 days of the date of this Order, as more specifically described above. IDAPA 31.01.01.165.02.

IT IS FURTHER ORDERED that this Order become effective on the service date shown on the front page.

THIS IS A FINAL ORDER. Any person interested in this Order (or in issues finally decided by this Order) or in interlocutory Orders previously issued in Case Nos. IPC-E-15-01, AVU-E-15-01, and PAC-E-15-03 may petition for reconsideration within twenty-one (21) days of the service date of this Order with regard to any matter decided in this Order or in interlocutory Orders previously issued in these cases. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. See *Idaho Code* § 61-626.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 20th day of August 2015.

PAUL KJELLANDER, PRESIDENT

Commissioner Smith did not participate in this case
MARSHA H. SMITH, COMMISSIONER

KRISTINE RAPER, COMMISSIONER

ATTEST:

Jean D. Jewell
Commission Secretary

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