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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE PETITION OF ROCKY MOUNTAIN POWER FOR MODIFICATION OF TERMS AND CONDITIONS OF PURPA PURCHASE AGREEMENTS AND FOR MODIFICATION OF ITS AVOIDED COST METHODOLOGY	**CASE NO. PAC-E-15-03** **PETITION OF ROCKY MOUNTAIN POWER**

PACIFICORP

DIRECT TESTIMONY

OF

PAUL H. CLEMENTS

Q. Please state your name, business address, and present position with Rocky Mountain Power (the "Company"), a division of PacifiCorp.

A. My name is Paul H. Clements. My business address is 201 S. Main, Suite 2300, Salt Lake City, Utah 84111. My present position is Senior Originator/Power Marketer for PacifiCorp Energy. PacifiCorp Energy and Rocky Mountain Power are divisions of PacifiCorp.

Q. How long have you been in your present position?

A. I have been in my present position since December 2004.

Q. Please describe your education and business experience.

A. I have a B.S. in Business Management from Brigham Young University. I have been employed with PacifiCorp since 2004 as an originator/power marketer responsible for negotiating qualifying facility contracts, negotiating interruptible retail special contracts, and managing wholesale or market-based energy and capacity contracts with other utilities and power marketers. I also worked in the merchant energy sector for approximately six years in pricing and structuring, origination, and trading roles for Duke Energy and Illinova.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support and present the Company's application to modify certain terms and conditions related to contracting and pricing for non-standard qualifying facility ("QF") contracts that the Company must enter into under the Public Utility Regulatory Policies Act of 1978 ("PURPA"). The Company is seeking immediate relief on one item in order to protect its customers in the near term. The Company is also seeking permanent implementation of two modifications to QF contracting and pricing procedures. These changes are necessary in order to maintain the "ratepayer indifference" standard required by PURPA in both the immediate near term and on a permanent basis. Specifically, the Company is requesting an order from the Idaho Public Utilities Commission ("Commission") directing implementation of the following:

1. Immediate reduction, on a temporary basis, of the maximum contract term for PURPA contracts between QFs and PacifiCorp from 20 years to five years, pending litigation of this case.
2. Permanent reduction of the maximum contract term for 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 more aligned with the Integrated Resource Plan ("IRP") cycle.
3. Modification of the Company's avoided cost methodology such that preparation of indicative prices for QFs shall reflect all active QF projects in the pricing queue ahead of any newly proposed QF request for indicative prices.

I provide evidence demonstrating how PacifiCorp customers could be adversely impacted by the Commission's February 6, 2015 order in Idaho Power Company's ("Idaho Power") Case No. IPC-E-15-01 if the Commission does not take immediate action in this proceeding. I also describe the significant increase the Company has experienced in PURPA contract requests in 2014 and 2015, how the increased activity harms customers, and why the requested modifications to the avoided cost contracting and pricing procedures are needed.

PacifiCorp currently has 189.6 megawatts ("MW") of existing PURPA contracts in Idaho and 275.5 MW of proposed PURPA contracts in Idaho, together totaling 465.1 MW of nameplate capacity. The magnitude and potential impact of this increased PURPA activity is best measured by comparing the total amount of existing and proposed Idaho PURPA projects to PacifiCorp's Idaho retail load. Using 2014 as an example, PacifiCorp's average total Idaho retail load was 432 MW and its minimum total Idaho retail load was 169 MW. The 465.1 MW of existing and proposed PURPA contracts in Idaho at their nameplate capacity would be enough to supply 108 percent of PacifiCorp's average Idaho retail load and 275 percent of PacifiCorp's minimum retail load. Expanding the analysis to PacifiCorp's six-state system, PacifiCorp currently has requests for 3,641 MW of new PURPA contracts system-wide, in addition to the 1,732 MW of QF contracts that are already executed.

I explain how this material increase in the number of PURPA projects requesting pricing in both Idaho and on PacifiCorp's system in other states will result in proposed Idaho projects receiving and entering into purchase obligations based upon pricing that is not reflective of the actual cost of the resource the QF will displace under the currently effective IRP methodology. I also provide evidence demonstrating the impact of PURPA contracts on customers' rates, and illustrate how the required 20-year contract term is (1) inconsistent with the Company's hedging and resource acquisition policies and practices for non-

PURPA energy purchases and (2) not aligned with the Company's IRP planning cycle and action plan. Lastly, I describe how, without the requested modification to contract term, PacifiCorp will be forced to continue to acquire long-term fixed price PURPA contracts even though PacifiCorp's 2013 IRP Update, which was filed with this Commission, shows that new long-term resources are not required until 2027. PacifiCorp's 2015 IRP, which is scheduled to be filed in March 2015, will show no new resource is required until 2028.

Q. Is the application supported by other witnesses?

A. Yes. Company witness Mr. Brian S. Dickman describes how the current avoided cost rate methodology does not recognize the impact of proposed QF contracts that are not yet signed but have requested indicative avoided cost prices and are actively pursuing a power purchase agreement ("PPA") with the Company – a shortcoming that leads to inflated and incorrect avoided cost prices in PURPA contracts due to QFs ability to enter into purchase obligations unilaterally. This shortcoming is particularly impactful when there are multiple PURPA contract requests at the same time, which is currently the case in Idaho and across PacifiCorp's six state system.

Q. Why are the requested modifications critical at this time?

A. First, the Company is seeking expedited and temporary relief based on the following event: Within five days of the Commission's February 6, 2015 Order ("Idaho Power Order"), PacifiCorp received four pricing requests totaling 130 MW from PURPA developers located in Idaho Power's service territory, who are now planning to obtain a transmission wheel to PacifiCorp in search of a PPA with more favorable terms. Because of this arbitrage, which could potentially cause immediate harm to the Company's retail customers, the Company is seeking an expedited order temporarily lowering the Company's maximum PURPA contract tenor from 20 years to five years.

Second, the Company seeks permanent changes to its PPA terms and conditions in general. The Company has reviewed its PURPA contracting and pricing procedures and believes that permanent, long-term changes to its PURPA contracts are critical to maintain the customer indifference standard required by PURPA and to protect the welfare of the Company's Idaho retail customers. In Order No. 33204, the Commission stated that utilities are in the best position to advise the Commission when changes to PURPA contract terms and conditions are warranted:

> *While we are pleased with the progression of the IRP methodology, avoided cost rates are not the only terms to a PURPA contract. The utilities are in the best position to inform the Commission if review of additional PURPA contract terms and conditions is warranted.*[1]

PacifiCorp routinely reviews PURPA contract terms and conditions and avoided cost methodologies, and recent events dictate that PacifiCorp petition this Commission for changes at this time.

Like Idaho Power, the Company has experienced a significant increase in QF pricing requests in Idaho and across its six-state system. Similar to Idaho Power, the Company has no need for resources for the next decade. Also similar to Idaho Power, the Company's hedging practices and policies are short-term in

[1] Order No. 33204 at 7.

nature. The Company's hedging program was modified as a result of a series of hedging collaborative workshops the Company held with stakeholders in 2011 and 2012 which reduced the Company's standard hedging horizon from 48 months to 36 months.

Given the magnitude of new QF requests, and considering the inherent uncertainties in projecting avoided cost rates out 20 years or more, current Idaho avoided cost rates are adversely impacting customers and will continue to do so for 20 years. Thus, in addition to the temporary, immediate change noted above, the Company also seeks two permanent changes. First, the Company requests approval of a permanent reduction in the maximum contract term for PURPA contracts, from 20 years to three years. Such a term would be more consistent with the Company's hedging and trading policies and practices for non-PURPA energy contracts and more aligned with the IRP cycle.

Second, Company witness Mr. Dickman reviewed the impact of the Company's large QF pricing queue on avoided costs in Idaho and determined that the currently approved methodology distorts avoided cost pricing because each project must be priced as if it were first in the queue. Because a purchase obligation may be created before each QF project can be re-priced to account for other projects that have entered into an obligation around the same time, the current methodology artificially inflates indicative avoided cost pricing for projects lower in the queue, harms retail customers if multiple purchase obligations are entered into based on that inaccurate pricing, and violates the ratepayer indifference standard under PURPA.

These events and the resulting consequences prompted the Company to file this petition to inform the Commission that changes are warranted.

Q. Describe the history and purpose of PURPA.

A. Congress enacted PURPA in response to the nationwide energy crisis of the 1970s. Its goal was to reduce the country's dependence on imported fuels by encouraging the addition of cogeneration and small power production facilities to the nation's electrical generating system.[2] PURPA requires electric utilities to purchase all electric energy made available by QFs 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."[3] The incremental cost to the utility means the amount it would cost the utility to generate or purchase the electric energy but for the purchase from the QF.[4] The incremental cost standard is intended to leave customers economically

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[2] *See, e.g.,* 16 U.S.C. § 2601 (Findings).

[3] The provisions of 16 U.S.C. § 824a-3 provide in pertinent part:

(a) Cogeneration and small power production rules

> Not later than 1 year after November 9, 1978, the Commission [FERC] shall prescribe, and from time to time thereafter revise, such rules as it determines necessary to encourage cogeneration and small power production, which rules require electric utilities to offer to -
>
> > (1) sell electric energy to qualifying cogeneration facilities and qualifying small power production facilities and
> >
> > (2) purchase electric energy from such facilities . . .

(b) Rates for purchases by electric utilities

> The rules prescribed under subsection (a) of this section shall insure that, in requiring any electric utility to offer to purchase electric energy from any qualifying cogeneration facility or qualifying small power production facility, the rates for such purchase -
>
> > (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 qualifying cogenerators or qualifying small power producers.
>
> No such rule prescribed under subsection (a) of this section shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy.

[4] The provisions of 16 U.S.C. § 824a-3(d) provide the following definition of "incremental cost of alternative electric energy":

> For purposes of this section, the term "incremental cost of alternative electric energy" means, with

indifferent to the source of a utility's energy by ensuring that the cost to the utility of purchasing power from a QF does not exceed the cost the utility would incur in the absence of the QF purchase.[5]

In 1980, FERC issued rules implementing PURPA in which it adopted what it called a utility's "avoided costs" as the standard for implementation of the incremental cost requirement.[6] While the applicable statutes and rules are matters of federal law, PURPA gives to state regulatory authorities the responsibility of determining a utility's avoided costs as well as terms and conditions of PURPA contracts.[7]

Q. Under PURPA, are utilities or their customers intended to subsidize QFs in order to achieve PURPA's policy goals?

A. Absolutely not. As this Commission and state regulators across the country have stated time and time again, under PURPA's original intent, retail customers should be indifferent to the purchase of QF power. This Commission stated as early as 1987 that,

> Under current FERC regulations implementing the Public Utility Regulatory Policies Act, ratepayers are supposed to be indifferent

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respect to electric energy purchased from a qualifying cogenerator or qualifying small power producer, the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source.

5 *See, e.g., Armco Advanced Materials Corp. v. Pennsylvania Pub. Util. Comm'n,* 535 Pa. 108, 634 A.2d 207, 209 (Pa. 1993).

6 *See American Paper Inst. v. American Elec. Power Serv.,* 461 U.S. 402, 406(1982) (stating that "the term full 'avoided costs' used in the regulations is the equivalent of the term 'incremental cost of alternative electric energy' used in § 210(d) of PURPA"). FERC's definitions of terms used in implementing PURPA are found at 18 C.F.R. § 292.101. The term "avoided costs" is defined as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." 18 C.F.R. § 292.101(b)(6).

7 *Idaho Power Co. v. Idaho Pub. Util. Comm'n.,* 155 Idaho 780, 782 (2013) ("*Idaho Power Co.*")(citing *FERC v. Mississippi,* 456 U.S. 742, 751 (1982)).

> or neutral as to whether they receive energy through a QF or a regulated utility. Stated differently, the price structure should enable utilities to integrate in a neutral and unbiased manner both utility and non-utility owned generating facilities into the long-run planning process and should provide similar economic criteria for development and operation of generating facilities regardless of facility ownership.[8]

FERC has likewise affirmed the need to ensure customer indifference to utility purchases of QF power, noting that, in enacting PURPA, "[t]he intention [of Congress] was to make ratepayers indifferent as to whether the utility used more traditional sources of power or the newly-encouraged alternatives."[9]

Under PURPA, then, customers must remain indifferent or unaffected by QF contracts. Further, as this Commission has noted "avoided cost rates are not the only terms to a PURPA contract."[10] Indeed, both avoided costs *and* other terms and conditions of PURPA contracts affect whether retail customers remain indifferent to the purchase of QF power. The modifications requested by the Company in this application are necessary to maintain this ratepayer indifference standard and are the primary means by which the Company and the Commission can protect customers from unnecessary price risk.

Q. Does the Commission have discretion to determine the appropriate contract term and avoided cost pricing methodology under PURPA?

A. Yes. Although PURPA's federal mandate requires utilities to purchase QF power, PURPA's scheme of cooperative federalism gives state regulatory agencies the

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[8] *In re Review of the Idaho Pub. Utils. Comm'n Policies Establishing Avoided Costs Under the Pub. Util. Regulatory Policies Act of 1978*, Case No. U-1500-170, Order No. 21249 (May 1987).
[9] *Southern Cal. Edison Co., et al.*, 71 FERC ¶ 61,269 at p. 62,080 (1995), overruled on other grounds, Cal. Pub. Util. Comm'n, 133 FERC ¶ 61,059 (2010).
[10] *In re Application of Idaho Power Co.*, Case No. IPC-E-14-30, Order No. 33204 at 8 (Jan. 8, 2015).

authority to protect retail customers from any unintended negative consequences of these mandatory purchases by delegating to state authorities the freedom to establish the key terms and conditions of PURPA contracts.[11] In crafting their methodologies for the details of PURPA contracts, FERC has explained its view that "states are allowed a wide degree of latitude in establishing an implementation plan for section 210 of PURPA, as long as such plans are consistent with [FERC's] regulations."[12] A critical element of the utility's must-purchase requirement under PURPA is the contract term. This is because FERC generally requires a utility to lock in forecasted avoided cost rates for the entire contract term.[13]

The contract term for PURPA contracts set by this Commission has never been static—it has varied since PURPA's inception. Initially, the Commission set PURPA contracts at 35 years to match the amortization period allowed for similar utility owned facilities, making financing easier, thus encouraging QF development.[14] Later, the Commission began to recognize concerns related to the risk and uncertainty inherent in long range forecasting and shortened the contract length to 20 years.[15] This time frame was shortened to only 5 years in 1996 and 1997 (first for QFs of 1 MW and larger, then for QFs under the 1 MW cap) in order to align the QF contract time frame with the utilities' acquisition

[11] *Idaho Power Co.,* 155 Idaho 780 at 782; *Exelon Wind I, LLC*, 766 F.3d 380 (5th Cir. 2014).
[12] *Cal. Pub. Util. Comm'n,* 133 FERC ¶ 61,059 at P 24 (2010).
[13] *See Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of PURPA*, 45 Fed. Reg. 12214, 12224 (1980).
[14] *See, e.g.* Order No. 29029 at 2 (describing the origin of PURPA regulation in Idaho).
[15] Order No. 21630.

strategies.[16] The Commission noted in that case that a 20 year contract obligation did not reflect the manner in which the utilities were acquiring power to meet new load, which at the time was through contracts with terms of five years or less, and that "it would be nothing more than an artificial shelter to the QF industry to provide those projects with contract terms not otherwise available in the free market."[17]

In 2002, the Commission raised the contract length back to 20 years, expressing concerns about a scarcity of QF contracts signed since the prior change.[18] Since then, concerns regarding the viability of QFs are no longer at the forefront. In 2015, the key concerns about PURPA contracts are similar to those that were present at the time of the Commission's 1996 and 1997 orders reducing the term to five years, *i.e.*, the current concerns flow from the magnitude of QF power flowing onto utilities' systems without any finding of utility need and resulting concerns about price risk, reliability, and customer indifference. As the Commission noted in a recent press release, the Commission has approved PURPA contracts for 400 MW of solar energy in just the past three months.[19] But the Commission noted, "PURPA does not address and FERC regulations do not adequately provide for consideration of whether the utility being forced to

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[16] *See* Order No. 26576; Order No. 29029 at 5 (describing the history of PURPA regulation in Idaho).
[17] Order No. 26576 at 13.
[18] See Order No. 29029 at 7 (stating that it "could not ignore the fact that since reducing the eligibility threshold to 1 MW and contract term to 5 years, there has been only one PURPA contract signed in Idaho.").
[19] Press Release, Idaho Public Utilities Commission, PUC reduces length of some PURPA contracts to five years (Feb. 5, 2015).

purchase QF power is actually in need of such energy."[20] The Commission has repeatedly expressed concerns about price and reliability impacts on Idaho customers in the past year, concerns that led the Commission to lower the approved length of PURPA contracts for Idaho Power down to five years in the Commission's February 6 Order.[21]

Q. Can a 20-year fixed-price contract term be considered a "subsidy" to a QF?

A. Yes. Given the typical contracting and hedging horizons for energy contracts in the utility industry, which are commonly limited to less than 36 months, it is extremely rare for a utility to voluntarily enter into a 20-year fixed-price energy contract without a specified energy resource need due to concerns about price risk, market liquidity, and other risk considerations. Under the Commission's current PURPA policies, however, any QF can obtain a 20-year, fixed-price energy contract at the Company's projected avoided cost, without any economic considerations or price 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. As this Commission has noted, "avoided cost rates are not the only terms to a PURPA contract." Contract lengths are also PURPA contract terms, and they carry with them their own economic value. To grant QFs access to long-term price certainty with no adjustment to the price to account for that certainty is granting QFs something no other market participant

[20] Order No. 33204 at 7.
[21] Order No. 33222.

enjoys. For this reason, I would view a guaranteed, fixed-price, 20-year contract at avoided cost to be a QF subsidy.

IMPACT OF THE COMMISSION'S IDAHO POWER ORDER: AN IMMEDIATE INCREASE IN QF PRICING REQUESTS

Q. How has the Idaho Power Order affected PacifiCorp?

A. On February 11, 2015, five days after that order, PacifiCorp received four new PURPA pricing requests in Idaho totaling 130 MW. In their requests, the developers specifically noted that they plan to interconnect the QF to Idaho Power Company's distribution/transmission system and wheel the power to Rocky Mountain Power. They further specifically request proposals for a minimum contracting term of 20 years. Their actions indicate that these developers would not have sought to sell to PacifiCorp had the 20-year contract term requirement not been reduced to five years for Idaho Power. In addition to these four formal requests, the Company has received several informal inquiries and expects to receive additional requests from projects located in Idaho Power's service territory. Since the current 465.1 MW of existing and proposed PURPA contracts in Idaho at their nameplate capacity is already enough to supply 108 percent of PacifiCorp's 2014 average Idaho retail load and 275 percent of PacifiCorp's 2014 minimum Idaho retail load, immediate action must be taken.

Q. Is it possible for projects to obtain the transmission rights required to move energy from Idaho Power's system to PacifiCorp's system?

A. Yes. PacifiCorp has reviewed Idaho Power's Open Access Same Time Information System ("OASIS") and confirmed that transmission is available.

Q. Is this type of wheel permitted under PURPA?

A. Yes. FERC's rules and orders contemplate that if a QF interconnects with one utility and wheels power to another utility's system, the second utility is required to purchase that power under PURPA. *See, e.g.,* 18 CFR §292.303.

Q. Is it just and reasonable and in the broad public interest for the Commission to allow QFs the ability to arbitrage between the various Idaho utilities based on different contract terms?

A. No. One group of Idaho customers should not be harmed by actions taken to protect another group of Idaho customers. The customer indifference standard should extend equally to all Idaho customers, regardless of the utility that serves them. In this case, actions taken by the Commission to protect Idaho Power customers may inadvertently result in harm to Rocky Mountain Power customers.

In a prior case brought before this Commission to address a similar situation in 1996 and 1997, Commission Staff stated its belief that "rules regarding contract length for PURPA contracts should be the same for all regulated electric utilities in Idaho to avoid disparate treatment."[22] The Commission ultimately agreed with the Staff's position in that case and incorporated their position in its order. In today's situation, similar to what occurred when found in these same circumstances in the past, Rocky Mountain Power customers should be afforded the same protections provided to other Idaho customers.

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[22] Case No. UPL-E-97-4, Order No. 27213.

Q. Notwithstanding the consequences you describe above that resulted from the Idaho Power Order, is there other evidence that supports PacifiCorp's requested modifications?

A. Yes. The Company will present substantial and compelling evidence demonstrating why the Company's requested modifications are necessary in order to maintain the "ratepayer indifference" standard. The consequences of the Idaho Power Order support the need for immediate relief but are not the sole reason the immediate and permanent changes are warranted at this time.

SIGNIFICANT INCREASE IN PURPA CONTRACT REQUESTS

Q. Has PacifiCorp executed a significant number of PURPA contracts in recent years in response to its federal obligation?

A. Yes. PacifiCorp currently manages 141 PURPA contracts totaling 1,732 MW of nameplate capacity across its six state system. Of this total, 97 projects totaling 1,553 MW (90 percent of the total PURPA MWs under contract) have online dates of 2007 or later, demonstrating that significant activity has occurred in the last seven to eight years. Of this total, 47 projects totaling 885 MW (slightly more than half of the total PURPA MWs under contract) have online dates of 2014 or later, further demonstrating the exponential increase in PURPA contract requests and resulting contracts that have occurred in the last two years. In Idaho, four projects totaling 164.7 MW came online in 2011 and 2012. Those four Idaho projects alone are close in nameplate capacity to PacifiCorp's minimum Idaho retail load in 2014 of 169 MW.

This dramatic increase in PURPA contract executions and pricing requests in Idaho and system-wide in the last several years demonstrates that additional review of contract and pricing methodology for non-standard Idaho QFs is warranted at this time and could not have been anticipated when the Commission reviewed the issue of contract term in previous cases.

Q. **Please describe the current queue of pricing requests for PURPA contracts in Idaho and across PacifiCorp's system.**

A. In Idaho, the Company currently has 12 project requests totaling 275.5 MW of nameplate capacity. The Company currently has requests from 89 projects totaling 3,641 MW of nameplate capacity system-wide. Table 1 shows the number of project requests and the total MWs by resource type for each of PacifiCorp's six states:

Table 1

State	Wind		Solar		Other		Total	
	Projects	MWs	Projects	MWs	Projects	MWs	Projects	MWs
California								
Idaho			11.0	271.0	1.0	4.5	12.0	275.5
Oregon			25.0	312.4	1.0	3.5	26.0	315.9
Utah	5.0	354.0	38.0	2,075.6			43.0	2,429.6
Washington								
Wyoming	8.0	620.0					8.0	620.0
TOTAL	**13.0**	**974.0**	**74.0**	**2,659.0**	**2.0**	**8.0**	**89.0**	**3,641.0**

Exhibit No. 1 provides detailed information on the pricing queue, including each project location (state), size (nameplate capacity), type (i.e. solar, wind), and proposed online date. Project names have been withheld to maintain confidentiality of the customer information.

Q. How does the number of executed Idaho PURPA contracts and proposed Idaho PURPA contracts compare to PacifiCorp's typical Idaho load requirements?

A. PacifiCorp has 189.6 MW of existing PURPA contracts in Idaho and 275.5 MW of proposed PURPA contracts in Idaho, together totaling 465.1 MW of nameplate capacity. Using 2014 as an example, PacifiCorp's maximum total retail load in Idaho was 818 MW, its minimum load was 169 MW, and its average load was 432 MW. The 465.1 MW of existing and proposed PURPA contracts in Idaho at their nameplate capacity would be enough to supply 108 percent of PacifiCorp's average Idaho retail load and 275 percent of PacifiCorp's minimum Idaho retail load.

Q. How does the number of executed PURPA contracts and proposed PURPA contracts across PacifiCorp's system compare to PacifiCorp's typical six state system load requirements?

A. PacifiCorp has 1,732 MW of existing PURPA contracts and 3,641 MW of proposed PURPA contracts, together totaling 5,373 MW of nameplate capacity. Using 2014 as an example, PacifiCorp's maximum total retail load across its six state system was 10,314 MW, its minimum load was 4,967 MW, and its average load was 6,844 MW. The 5,373 MW of existing and proposed PURPA contracts at their nameplate capacity would be enough to supply 79 percent of PacifiCorp's average retail load and 108 percent of PacifiCorp's minimum retail load.

DISTORTION OF INDICATIVE AVOIDED COST PRICING DUE TO INCREASE IN PURPA CONTRACT PRICING QUEUE

Q. How is indicative pricing calculated if you have multiple proposed PURPA contracts in the pricing queue?

A. Each proposed QF project is provided an indicative price assuming the project requesting pricing is at the top of the pricing queue, meaning the existence of other proposed or queued QF projects is not factored into the indicative price. Therefore, each project is provided an indicative price based on the Company's highest marginal or avoided resource costs. For example, assuming PacifiCorp's highest marginal or avoidable cost for a given time period is a 25 MW market purchase at $35 per megawatt-hour ("MWh"), and the next highest marginal or avoidable cost for the same time period is a second 25 MW market purchase at $30 per MWh. Under the current approved methodology, a proposed 20 MW QF would receive an indicative price based on avoiding 20 MW of the 25 MW purchase at $35 per MWh. If the Company were to receive a second 20 MW pricing request for a different PURPA project, it too would receive an indicative price based on the assumption that it avoids 20 MW of the 25 MW purchase at $35 per MWh, because the current methodology does not allow the Company to account for the existence of the first proposed project when providing pricing for the second proposed project. If both parties were to unequivocally commit themselves to sell to PacifiCorp at around the same time, PacifiCorp could not re-price the second project to reflect the fact that the first project already "avoided" the same resource. In my hypothetical example, both 20 MW projects, or 40 MW total, would be priced as if they were avoiding the single 25 MW resource at $35 per MWh. In reality, if considered together they would be avoiding 25 MW of the $35 per MWh resource and 15 MW of the $30 per MWh resource. In this example, the inability to account for the first proposed contract when providing pricing for the second proposed contract results in customers paying a QF $35 per MWh for 15 MW when the actual cost of the 15 MW being avoided by that QF is only $30 per MWh. This $5 per MWh difference violates the ratepayer indifference standard.

Q. What is the impact of a very large pricing queue (i.e. multiple proposed PURPA projects requesting contracts) on indicative pricing?

A. A very large pricing queue results in indicative pricing being provided to proposed PURPA projects that is far in excess of actual avoided costs if all queued projects are considered. The larger the queue, the greater the problem. In my example above, I described how two hypothetical 20 MW projects received pricing based on the single highest cost resource, but one of them actually avoided a lower cost resource when considered together. The result was an avoided cost that was $5 per MWh too high. If the queue has dozens of PURPA projects requesting pricing, as is currently the case, this issue is exacerbated. Multiple projects may receive indicative pricing based on the highest cost resource, but when the dozens of projects are considered together, the projects at the bottom of the queue are likely avoiding much lower cost resources. This results in payments to QFs that exceed the cost of the resource that is being avoided. This increases costs to customers and is not consistent with the ratepayer indifference standard mandated by PURPA. Company witness Brian Dickman provides additional evidence and supporting testimony regarding the impact of the existing pricing queue on avoided cost pricing. In his testimony, he describes how the difference in avoided costs from the top to the bottom of a pricing queue with approximately 3,000 MW, or 641 MW less than the current PacifiCorp pricing queue of 3,641 MW, is approximately $18 per MWh - meaning indicative pricing for the last project request received could be as much as $18 per MWh higher than avoided costs if all the project requests ahead of it in the 3,000 MW queue enter into purchase obligations.

THE COMPANY'S IDAHO PURPA CONTRACTS WILL RESULT IN HIGHER CUSTOMER RATES, IN CONFLICT WITH THE RATEPAYER INDIFFERENCE STANDARD

Q. What impact should PURPA contracts have on customer rates?

A. PURPA contracts should have <u>no</u> impact on customer rates. As this Commission and state regulators across the country have stated time and time again, retail customers should be indifferent to the purchase of QF power. As FERC has noted, in enacting PURPA, "[t]he 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 Co., San Diego Gas & Elec. Co.*, 71 FERC ¶ 61,269 at p. 62,080 (1995).

In short, customers must remain indifferent or unaffected by PURPA contracts. The modifications requested by the Company in this application are necessary to maintain this indifference standard.

Q. Why is it critical to make needed modifications to pricing and contracting procedures quickly once they have been identified?

A. As mentioned earlier in my testimony, PacifiCorp currently has 189.6 MW of existing PURPA contracts in Idaho and 275.5 MW of proposed PURPA contracts in Idaho, together totaling 465.1 MW of nameplate capacity. The Company has 141 existing (executed) PURPA contracts totaling 1,732 MW of nameplate capacity across its six state system. Under PacifiCorp's multi-state jurisdictional cost allocation model, PURPA contracts are considered system resources and are allocated to each of the six states based on the System Generation allocation factor. Idaho's allocated share is typically around six percent. The expected system wide costs (payments to QFs) over the next ten years from PacifiCorp's executed PURPA contracts is $2.6 billion. In 2015 alone, the projected payment to QFs is $170.5 million, with Idaho's allocated share at $10.2 million.[23] If these projects had been priced incorrectly by just 10 percent, it would create a $1.0 million impact in 2015 for Idaho customers. That 10 percent impact would grow to a total of $15.5 million in additional costs to Idaho customers over the ten year period starting in 2015. With a pricing queue that currently totals 3,641 MW, or more than double (in MW) the size of the $2.6 billion worth of current PURPA contracts to which the Company is already obligated, it is imperative that the indicative pricing provided to prospective PURPA projects be accurate and reflective of the Company's actual projected avoided costs. Failure to implement the modifications proposed by the Company in this case will result in significant

[23] Assuming an allocation factor of 6 percent.

irreversible harm to customers in the form of higher retail rates than what would otherwise occur without the PURPA contracts.

20 YEAR PURPA CONTRACTS ARE INCONSISTENT WITH CURRENT HEDGING PRACTICES AND RISK POLICIES AND REQUIRE CUSTOMERS TO BEAR AN INAPPROPRIATE AND UNNECESSARY LEVEL OF PRICE RISK

Q. When the Company considers purchasing power from a third party, does the Company first review the proposed purchase from a resource need and a risk-management perspective?

A. Yes. The Commission expects the Company to serve its customers with least-cost, least-risk resources. For that reason, the Company has integrated resource planning processes and risk-management policies it applies to evaluate any proposed energy contracts, to ensure the contracts are reasonable and prudent.

Q. Does the Company apply its integrated resource planning process and internal risk management policies to PURPA contracts?

A. No, not in the same way as it does for non-PURPA contracts. The Company cannot refuse to execute PURPA contracts based on the price or the contract term, or based on other transaction parameters that it would normally not accept for non-PURPA contracts. Under PURPA, the Company must purchase QF energy and capacity regardless of whether the Company needs the power, on terms and conditions established by its state commissions.

Q. How does the Company manage PURPA contract risk?

A. While the Company has some limited ability to negotiate PURPA contract terms and conditions, and while the Company uses its non-QF resources to integrate QF power into its system as efficiently and reliably as possible, PURPA requires the Company to rely primarily on its state regulatory commissions to regulate customer exposure to risk through the establishment of terms and conditions of its PURPA contracts.

Q. PURPA contracts aside, please generally describe the current electricity and natural gas hedging practices and policies at PacifiCorp.

A. The Company modified its hedging horizon for natural gas and power from 48 months to 36 months as a result of hedging collaborative workshops it held with stakeholders in 2011 and 2012. The Company's trading policies and procedures are outlined in the PacifiCorp Energy Commercial & Trading Risk Management Policy. That policy sets forth how the Company identifies, assesses, monitors, reports, manages and mitigates each of the various types of commercial risk associated with energy trading. Energy commodities include, but are not limited to, physical and financial transactions of electricity and natural gas, #2 fuel oil, unleaded gasoline, renewable energy credits, SO_2 emission allowances, and greenhouse gas allowances. PacifiCorp's commercial & trading organization within PacifiCorp Energy manages the energy commodity position and utilizes PacifiCorp's assets and liabilities (loads, generating resources, contractual rights, and obligations) to (i) ensure reliable sources of electric power are available to meet PacifiCorp's customers' needs and (ii) reduce volatility of net power costs for PacifiCorp's customers.

PacifiCorp's commodity risks are managed through a control and limit structure that defines the maximum levels of market risk and credit capacity permissible for commercial & trading to engage in trading and risk management activities. Compliance with this policy is mandatory.

PacifiCorp's current practice is to actively manage electricity and natural gas short and long positions that are 36 months out and nearer, meaning up to three years from today. Traders have risk limits that they must maintain in order to limit customer price exposure to the Company's open position over this three year time horizon. This trading practice ensures reliable sources of electric power are available to meet PacifiCorp customers' needs and reduces volatility of net power costs.

Q. Do PacifiCorp traders actively manage or hedge positions beyond the prompt 36 months?

A. No. The Company's practice since it completed the hedging collaborative workshops in 2012 has been to limit hedges to 36 months or less unless stakeholders express interest for longer term hedges. There has been no such expressed interest for electricity hedges beyond 36 months since that time. The Company's risk management metrics are also limited to 36 months.

Q. Why are these risk management and hedging policies and requirements not applicable to the Company's PURPA contracts?

A. The Company is obligated by law to purchase electricity from QFs at prices and terms set forth by the appropriate state commissions. In this sense, the Company's primary vehicle for risk management review of PURPA contracts are the policy decisions made by each state commission.

Q. What process would PacifiCorp undertake when contemplating a non-PURPA transaction that exceeds the typical 36-month time horizon?

A. Non-PURPA transactions that exceed 36 months in effective transaction period require extensive analysis and progressively higher level of management review. The analysis includes a review of the need for the transaction, a comparison of the contemplated transaction to other available transactions that meet the same need, a thorough economic analysis to demonstrate that the transaction is the least-cost, least-risk way to meet the identified need, and an extensive review of credit terms and contract terms. Typically the level of detail, documentation, and review increases commensurate with the size and duration of the transaction, which also increases the level of management approval that is required.

The Company primarily enters into long-term transactions (those that exceed 36 months) 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 such that a long-term resource is required to meet customer load requirements.

Q. When the Company enters into a long-term transaction as a result of the IRP action plan, what additional steps are taken to protect customers?

A. The Company typically utilizes a rigorous request for proposal ("RFP") process to acquire any long-term transaction or resource need directed by the IRP action plan. This process often involves extensive input from regulators in the drafting and management of the RFP. In fact, the process often includes independent evaluator[24] review of the process and ultimate results. This robust process ensures the Company acquires only what is needed and results in a long-term transaction at the lowest cost possible. In addition to the extensive RFP process, any long-term transaction goes through the analysis and review process I described in conjunction with the PacifiCorp Energy Commercial & Trading Risk Management Policy.

Q. **Do these same steps occur prior to entering into a PURPA contract?**

A. No. PURPA contracts do not go through the same extensive IRP process to determine if they are needed. PURPA contracts do not go through the same competitive bid RFP process including oversight by an independent evaluator to ensure they are lowest cost. PURPA contract executions are not limited to the size of the resource need in the IRP action plan. And, PURPA contracts do not receive the same upper management review and analysis because upper management does not have the discretion to refuse the mandatory purchase obligation and the 20 year contract term established by the Commission. The Company is asking the Commission to use its discretion to implement the changes necessary to protect customers.

Q. **Why is such a rigorous review process necessary when entering into long-term transactions, and why does the Company generally limit trading and hedging activities to the prompt 36 months?**

A. The primary reason is long-term fixed price energy contracts carry significant

[24] An independent evaluator is a third party who is appointed by PacifiCorp's regulators to oversee the RFP process to ensure fairness throughout the process and to ensure the bids are accurately evaluated.

price risk. The market becomes more and more uncertain as you move further into the future, and it is difficult to forecast with reasonable certainty what prices will be far out into the future. Long-term fixed price transactions often move in or out of the money over time as the forward price curve changes. For these reasons, unless the Company has a demonstrated need for resources in its integrated resource plan, it does not pursue long-term transactions.

Q. Is there additional market and industry evidence that supports the Company's 36 month trading and hedging horizon?

A. Yes. In the unregulated wholesale energy marketplace, very few transactions occur beyond a six year time horizon and the highest volume is within one year. When the Company has entered into long-term, non-QF transactions in the past several years it is the result of a specific need for a resource identified in the IRP and the contracts are typically backed by an identified firm resource (i.e. a utility has load growth, generating unit retirements, or expiring contracts and needs a resource, so it contracts to buy the output from a certain generator). Most of these long-term transactions occur through a rigorous, transparent, and competitive request for proposals processes.

Further evidence of the industry preference for shorter term fixed price contracts is found in the practices of most of PacifiCorp's combined heat and power (CHP) QFs. CHP QFs generally do not need long-term contracts for financing purposes (most use balance sheet financing), so these types of QFs evaluate a desired contract term from a risk management perspective. Like most utilities, CHP QFs typically elect short term contracts with PacifiCorp even when

20 year terms are available. In fact, most elect annual contracts that are renewed each year at the then-current avoided costs. These CHP QF customers have told PacifiCorp that they are not energy traders and therefore prefer to take the spot or near term avoided cost price in order to eliminate the price risk that comes from long-term fixed price contracts.

Q. Can you provide an example of the price risk associated with a long-term fixed price contract?

A. Yes. The electricity and natural gas markets have fallen dramatically in the past year as oil prices have also declined. On August 1, 2014, a ten year fixed price contract for a seven day by 24 hour electricity product at the Mid-Columbia ("Mid-C") wholesale power market trading hub was priced at $45.87 per MWh. On February 2, 2015, just six months later, that same ten year contract was priced at $38.11 per MWh. The 10 year electricity market declined 17 percent in just six months. Hypothetically, had the Company purchased 100 MW of this ten year fixed price electricity on August 1, 2014 at $45.87 per MWh, just six months later the Company would have a mark-to-market loss of $68.0 million on the contract.

By comparison to this 100 MW ten-year example, PacifiCorp currently has 275.5 MW of proposed PURPA contracts in Idaho seeking 20 year fixed price contracts. The price risk associated with this large number of proposed long-term fixed price contracts is substantial and should not be borne by customers.

Q. How do you respond to the argument that market prices are currently "low" and therefore PacifiCorp should lock in as much energy as possible?

A. Locking in a price because you are speculating that the price is "low" is not hedging – it is speculative trading. PacifiCorp customers are not commodity traders. PacifiCorp customers expect the Company to provide safe and reliable energy while employing the "least cost least risk" principle. Taking a long-term fixed price position in a commodity does not follow this principle.

Q. Has this long-term price risk been evidenced in the Company's existing PURPA contracts?

A. Yes. The Company currently has 141 PURPA contracts totaling 1,732 MW of nameplate capacity across its six state system. As I mentioned above, Idaho's allocated share of these contract costs averages approximately 6 percent. Over the next ten years, the Company is under contract to purchase 38.9 million MWhs under its PURPA contract obligations at an average price of $66.32 per MWh. The average forward price curve for Mid-C over this same ten years is $38.11 per MWh[25], or a difference of $28.21 per MWh.

Q. Under current policies and QF pricing methods, can the Company protect customers from long-term price risk when entering into PURPA contracts?

A. No. Unlike a need based long-term transaction, a mandatory purchase under a PURPA long-term fixed price contract must be executed regardless of need. Consequently, these long-term contracts unnecessarily expose customers to price risk that is not reflected in the contract price.

[25] Based on a February 2, 2015 forward price curve for a 7x24 (flat) electricity product.

LONG-TERM RESOURCE PLANNING: PACIFICORP'S IRP PROCESS AND CURRENT RESOURCE NEEDS

Q. How does the Company determine its long-term resource needs?

A. The Company's long-term planning and resource decisions are thoroughly evaluated through the Company's IRP process. PacifiCorp's IRP is developed with participation from public stakeholders, including regulatory staff, advocacy groups, and other interested parties. The planning process entails: (1) developing an assessment of resource need via a load and resource balance, reflecting current load growth forecasts and existing resources and contracts over a twenty year planning horizon; (2) producing a range of different resource portfolios that could be used to meet the projected resource need; and (3) evaluating the comparative cost and risks of each resource portfolio, taking into consideration a wide range of planning uncertainties, in order to identify the least cost and least risk preferred portfolio. Once a preferred portfolio is selected, an action plan is developed that identifies the specific resource actions the Company will take over the next two to four years to implement its resource plan.

Q. How does the IRP influence the types of long-term transactions entered into by the Company?

A. The Company would not plan to enter into long-term transactions unless a long-term resource need is identified in the IRP preferred portfolio. As noted above, long-term resource needs are typically identified in the IRP only after lower-cost, lower-risk short-term resource opportunities are exhausted such that a long-term resource is required to meet customer load requirements. If the IRP identifies the need for a long-term resource in the near-term, an IRP action item would specify the Company's plans to acquire the resource, which might include issuance of a request for proposal.

Q. What long-term transactions have been included in recent and current IRP action plans?

A. The 2013 IRP, which is the reference for current avoided costs in Idaho, included a combined cycle combustion turbine ("CCCT") gas plant in 2024. Due to the timing of the identified need for this resource, the 2013 IRP action plan did not include any action items to procure this long-term resource. The 2013 IRP Update, filed with the Commission in March 2014, pushed the CCCT out to 2027. Again, due to the timing of this identified need, the Company has not developed an action item to procure this long-term resource. The Company is in the process of preparing its 2015 IRP, which will be filed with the Commission in March 2015. The 2015 IRP draft preferred portfolio pushes the CCCT out even further to 2028. As in the 2013 IRP and the 2013 IRP Update, the 2015 IRP draft action plan does not include any action items to procure this long-term resource.

Q. What conclusion can you draw from the draft 2015 IRP preferred portfolio and associated draft action plan?

A. The Company does not have a need for a new long-term resource until 2028, and due to the timing of this need, the Company will not have any action items to procure a new long-term resource in the next two to four years.

Q. How is the Company's proposal to limit QF contract terms to three years in length aligned with the IRP planning process?

A. The full IRP is published every other year, with an update published in the off years. As described earlier in my testimony, the IRP process includes a rigorous review of the Company's resource needs by evaluating its load and resource balance and establishing a least cost, least risk resource plan through comprehensive and rigorous modeling of numerous resource alternatives. The planning environment is constantly changing. This is evidenced by changes in the Company's load and resource balance, state and federal environmental policies, wholesale power and natural gas prices, market products, market rules and contracting practices, and cost and performance of new generating technologies, to name a few. While the Company's planning process is robust and designed to reasonably capture a wide range of uncertainties, the magnitude of the various planning uncertainties grows as you get further out into the IRP 20-year planning horizon. It is for this very reason that IRP action items focus on the front two to four years of the planning period and that the IRP planning process is repeated every two years with updates in the off years. Even within these biannual planning cycles, material changes in Company's resource needs have been observed from one IRP to the next. The Company's proposal to limit QF contract terms to three years in length is more aligned with the two year IRP planning cycle, and the associated two to four year action plan period. Aligning a QF contract term limit to the IRP planning cycle will ensure avoided cost pricing remains consistent with the most up-to-date information regarding the Company's resource needs and limit long-term price risk.

Q. Please summarize your testimony and the Company's requested relief.

A. The Company is seeking immediate relief on one item and permanent implementation of two modifications to QF contracting and pricing procedures. These changes are necessary in order to maintain the ratepayer indifference standard required by PURPA and to protect Idaho customers. Specifically, the Company is requesting an order from the Commission directing implementation of the following:

1. Immediate reduction, on a temporary basis, of the maximum contract term for PURPA contracts between QFs and PacifiCorp from 20 years to five years, pending litigation of this case.
2. Permanent reduction of the maximum contract term for 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 more aligned with the IRP cycle.
3. Modification of the Company's avoided cost methodology such that preparation of indicative prices for QFs shall reflect all active QF projects in the pricing queue ahead of any newly proposed QF requests for indicative prices.

The immediate short-term relief is necessary to protect Rocky Mountain Power customers from being adversely impacted by the Idaho Power Order. The Company has received 130 MW of pricing requests from proposed QFs who now intend to wheel power to PacifiCorp to obtain PURPA contracts with a 20-year term. This action, if allowed to continue, will result in disparate treatment of Rocky Mountain Power's customers, an unfair result that is inconsistent with the Commission's historical treatment of utilities in similar circumstances.[26]

In addition to seeking immediate, temporary relief, the Company is seeking longer-term relief as a result of a significant increase in PURPA contract requests received in 2014 and 2015, activity that Rocky Mountain Power believes will harm customers unless the Commission directs permanent modifications to the Company's current Idaho avoided cost contracting and pricing procedures. As noted, PacifiCorp currently has pending requests for 275.5 MW of new PURPA contracts in Idaho, in addition to the 189.6 MW of existing contracts. By comparison, Rocky Mountain Power's minimum retail load in Idaho in 2014 was 169 MW. Across its six-state system, PacifiCorp currently has 3,641 MW of new PURPA contract requests, in addition to the 1,732 MWs of PURPA power already under contract. This striking increase in new QF activity exposes customers to higher price risk due to the sheer volume of power that may become locked in at a fixed price for decades under current Commission contract terms.

Given this exponential increase in QF contracting activity, 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 puts retail customers at risk of harm due to significant and unnecessary exposure to long-term price risk, a level of risk the Commission would not accept in the context of a non-PURPA transaction. The Company has

[26] *See* Case No. UPL-E-97-4, Order No. 27213.

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.

The Company can mitigate the risk to customers of other long-term transactions. When the Company considers non-PURPA transactions, the Company first reviews the proposed purchase from a risk-management perspective. The Company's practice since it completed the hedging collaborative workshops in 2012 has been to limit hedges to 36 months or less unless stakeholders express interest for longer term hedges. As explained above, transactions that exceed 36 months require extensive analysis and progressively higher level of management review. The primary reason that such a rigorous review process is necessary when entering into long-term transactions, and the reason the Company generally limits trading and hedging activities to the prompt 36 months, is that long-term fixed price energy contracts carry significant price risk. The market becomes more and more uncertain as you move further into the future, and it is difficult to forecast with reasonable certainty what prices will be far out into the future. Moreover, the Company does not typically enter into long-term transactions unless those transactions have been identified as least cost, least risk transactions through the IRP process. Even then, the Company typically utilizes a rigorous RFP process to acquire any long-term resource identified by the IRP action plan. At this point in time, the Company does not have a need for a new long-term resource until 2028, and due to the timing of this need, the

Company will not have any action items to procure a new long-term resource in the next two to four years.

The situation facing the Company and its Idaho customers is one that they have experienced in the past: significant industry changes, low gas prices, surplus of energy and capacity, and the primary use of short-term purchases to meet load. In proceedings in 1996 and 1997, the Commission appropriately responded to this precise situation by reducing PURPA contract terms from 20 years to five years:

> Significant changes have swept through the electric industry since we last examined the issue of contract length. The FERC has mandated open access to the transmission system, thermal technologies have improved, gas prices are low, there is a considerable surplus of energy available in this region resulting in very low spot market prices for electricity and, finally, even the continued existence of PURPA is being called into question. We find that as the industry as a whole continues to transform to a more free market model, we cannot justify obligating utilities to 20-year contracts for PURPA power. <u>As the utilities in this case note, such an obligation does not reflect the manner in which they are currently acquiring power to meet new load; through short-term (five years or less) purchases. Consequently, it would be nothing more than an artificial shelter to the QF industry to provide those projects with contract terms not otherwise available in the free market. We can find no justification for insisting that Idaho's investor-owned utilities and their ratepayers assume such an obligation simply to foster one particular segment of an increasingly competitive industry.</u> We find, therefore, that Idaho's investor-owned utilities shall not be required to offer contracts to QFs in excess of five years until further action is taken by this Commission. This ruling, however, does not prevent utilities from offering for approval QF contracts with terms that exceed five years should the utilities believe that such contracts are in the best interests of their ratepayers.

See Case No. IPC-E-95-9, Order No. 26576; Case No. IPC-E-97-9, Order No. 27111; Case No. WWP-E-97-8, Order No. 27212; Case No. UPL-E-97-4, Order No. 27213 (emphasis added). The Company requests that the Commission respond to the current situation as it did in the 1996 and 1997 proceedings: by reducing the maximum PURPA contract term; in this case, from 20 years to three years.

Moreover, the current, Commission-approved methodology allows QFs to lock in long-term contracts with pricing that is above the Company's incremental cost of energy and capacity because projects that are in the pricing queue ahead of the next proposed project are not considered and included in the calculation of indicative pricing. Brian Dickman describes how this impact can be as much as $18 per MWh for a queue that includes approximately 3,000 MW of queued QF power, or 641 MW less than the current queue. Given the magnitude of new QF requests, this one-way error is becoming progressively more harmful to retail customers. Therefore, the Company requests the Commission direct that preparation of indicative prices for QFs reflect all active QF projects in the pricing queue ahead of any newly proposed QF request for indicative prices.

The requested temporary relief and the permanent modifications to the Company's current Idaho avoided cost contracting and pricing procedures are required at this time to maintain the ratepayer indifference standard required by PURPA and to protect Idaho customers from near-term and ongoing harm.

Q. Does this conclude your direct testimony?

A. Yes.

Case No. PAC-E-15-03
Exhibit No. 1
Witness: Paul H. Clements

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Paul H. Clements

February 2015

Location	Type	Size (MW)	Proposed Online Date
Idaho	Gas	4.5	08/01/2015
Idaho	Solar	40.0	08/01/2016
Idaho	Solar	20.0	08/01/2016
Idaho	Solar	20.0	08/01/2016
Idaho	Solar	50.0	08/01/2016
Idaho	Solar	20.0	10/31/2016
Idaho	Solar	20.0	10/31/2016
Idaho	Solar	21.0	12/31/2016
Idaho	Solar	20.0	12/31/2016
Idaho	Solar	20.0	12/31/2016
Idaho	Solar	20.0	12/31/2016
Idaho	Solar	20.0	12/31/2016
Oregon	Geothermal	3.5	05/01/2014
Oregon	Solar	10.0	12/31/2015
Oregon	Solar	0.8	12/31/2015
Oregon	Solar	10.0	12/31/2016
Oregon	Solar	10.0	12/31/2016
Oregon	Solar	7.5	12/31/2016
Oregon	Solar	10.0	12/31/2016
Oregon	Solar	10.0	12/31/2016
Oregon	Solar	10.0	12/31/2016
Oregon	Solar	10.0	12/31/2016
Oregon	Solar	10.0	12/31/2016
Oregon	Solar	8.0	12/31/2016
Oregon	Solar	9.9	12/31/2016
Oregon	Solar	9.9	12/31/2016
Oregon	Solar	9.9	12/31/2016
Oregon	Solar	10.0	12/31/2016
Oregon	Solar	10.0	12/31/2016
Oregon	Solar	9.9	12/31/2016
Oregon	Solar	7.5	12/31/2016
Oregon	Solar	10.0	12/31/2016
Oregon	Solar	10.0	12/31/2016

Location	Type	Size (MW)	Proposed Online Date
Oregon	Solar	9.9	12/31/2016
Oregon	Solar	9.9	12/31/2016
Oregon	Solar	45.0	12/31/2016
Oregon	Solar	20.0	12/31/2016
Oregon	Solar	44.2	01/01/2017
Utah	Solar	50.0	08/31/2015
Utah	Wind	80.0	10/01/2015
Utah	Wind	45.0	11/01/2015
Utah	Solar	50.4	12/01/2015
Utah	Solar	65.6	12/15/2015
Utah	Solar	50.4	12/15/2015
Utah	Solar	10.0	12/31/2015
Utah	Solar	80.0	12/31/2015
Utah	Solar	80.0	12/31/2015
Utah	Solar	80.0	12/31/2015
Utah	Solar	5.0	12/31/2015
Utah	Solar	21.0	01/01/2016
Utah	Solar	80.0	01/01/2016
Utah	Solar	1.0	04/03/2016
Utah	Solar	80.0	06/01/2016
Utah	Solar	80.0	06/01/2016
Utah	Solar	80.0	06/01/2016
Utah	Solar	80.0	06/01/2016
Utah	Solar	80.0	06/01/2016
Utah	Solar	80.0	06/01/2016
Utah	Solar	80.0	10/01/2016
Utah	Solar	20.0	10/01/2016
Utah	Solar	80.0	11/01/2016
Utah	Solar	80.0	11/01/2016
Utah	Solar	80.0	11/01/2016
Utah	Solar	80.0	11/01/2016
Utah	Solar	1.0	12/31/2016
Utah	Solar	20.0	12/31/2016
Utah	Solar	40.0	12/31/2016
Utah	Solar	50.0	12/31/2016
Utah	Solar	15.0	12/31/2016
Utah	Solar	14.5	12/31/2016

Location	Type	Size (MW)	Proposed Online Date
Utah	Solar	7.5	12/31/2016
Utah	Solar	50.0	12/31/2016
Utah	Solar	80.0	12/31/2016
Utah	Solar	80.0	12/31/2016
Utah	Solar	6.0	12/31/2016
Utah	Wind	69.0	12/31/2016
Utah	Solar	78.2	12/31/2016
Utah	Solar	80.0	01/01/2018
Utah	Solar	80.0	01/01/2018
Utah	Wind	80.0	01/01/2018
Utah	Wind	80.0	01/01/2018
Wyoming	Wind	80.0	07/31/2015
Wyoming	Wind	80.0	12/01/2015
Wyoming	Wind	80.0	01/01/2016
Wyoming	Wind	60.0	01/01/2016
Wyoming	Wind	80.0	12/31/2017
Wyoming	Wind	80.0	12/31/2017
Wyoming	Wind	80.0	12/31/2017
Wyoming	Wind	80.0	12/31/2017