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 Rocky Mountain Power.

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 the maximum allowable contract term for qualifying facility ("QF") contracts that the Company must enter into under the Public Utility Regulatory Policies Act of 1978 ("PURPA"). The Company is seeking a modification to the maximum contract term of QF contracts executed under both Schedules 37 and 38. This change is necessary in order to maintain the "ratepayer indifference" standard required by PURPA. Specifically, the Company is requesting an order from the Public Service Commission of Utah ("Commission") directing implementation of a reduction of the maximum contract term for PURPA contracts from 20 years (or possibly longer) 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.

I describe the significant increase the Company has experienced in PURPA contract requests in 2014 and 2015, how the increase in requests increases risk to customers, and why the requested modification to the avoided cost contract term is needed.

The Company currently has 1,041 megawatts[1] ("MW") of existing PURPA contracts in Utah and 2,253 MW of proposed PURPA contracts in Utah, together totaling 3,294 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 Utah PURPA projects to the Company's Utah retail load. Using 2014 as an example, the Company's average total Utah retail load was 2,959 MW and its minimum total Utah retail load was 2,033 MW. The 3,294 MW of existing and proposed PURPA contracts in Utah at their nameplate capacity would be enough to supply 111 percent of the Company's average Utah retail load and 162 percent of the Company's minimum Utah retail load. Expanding the analysis to the Company's six-state system, PacifiCorp currently has requests for 3,692 MW

[1] Unless specifically noted, values in my testimony are rounded to the nearest full MW.

of new PURPA contracts system-wide, in addition to the 1,992 MW of QF contracts that are already executed.

I explain and illustrate how the required 20-year contract term is (1) inconsistent with the Company's hedging practices implemented after careful review by stakeholders in a recent collaborative, (2) inconsistent with resource acquisition policies and practices for non-PURPA energy purchases, and (3) not aligned with the Company's IRP planning cycle and action plan. I also provide evidence demonstrating the impact of PURPA contracts on customers' rates. I also 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 2015 IRP, which was filed in March 2015, shows no new resource is required until 2028.

Q. Why is the requested modification critical at this time?

A. PacifiCorp routinely reviews PURPA contract terms and conditions and avoided cost methods, and recent events dictate that the Company petition this Commission for a change at this time.

The Company has experienced a significant increase in QF pricing requests in Utah and across its six-state system. The Company has no need for resources for the next decade. The Company's hedging practices and policies are short-term in 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 Utah avoided cost rates expose customers to unreasonable fixed-price risk for 20 years. To protect customers from this risk on an on-going basis, the Company requests approval of a 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.

BACKGROUND

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

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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

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 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] The Commission initiated Docket No. 80-999-06 to address those

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> 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 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.*, 316 P.3d 1278, 1280 (2013) ("*Idaho Power Co.*")(citing *FERC v. Mississippi*, 456 U.S. 742, 751 (1982)).

matters.

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, while discussing the general goals of PURPA in its early years of implementation, stated:

> We wish to promote the development of the specific QF projects and the overall QF capacity which will serve the economic interests of the ratepayers. We wish to discourage QF development which requires a subsidy from the ratepayers to the QF developers. We understand these positions to be the appropriate interpretation of the PURPA full avoided cost based QF pricing and ratepayer neutrality mandates.[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, this Commission has recognized that the term of a PURPA contract and the rates to be paid under that contract are interrelated.[10] Indeed, both avoided costs *and* other terms and conditions of PURPA contracts affect whether retail

[8] *In the Matter of the Implementation of Rules Governing Cogeneration and Small Power Production in the State of Utah,* Docket No. 80-999-06, Report and Order (April 3, 1987), p. 4.
[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 the Matter of the Implementation of Rules Governing Cogeneration and Small Power Production in the State of Utah,* Docket No. 80-999-06, Report and Order (March 14, 1985), pp. 37-38 (Providing small power producers with fixed fuel cost the option of a 35-year (rather than 20-year) contract "will necessitate a recalculation of the capacity payments for such an extended contract, which the Commission understands will be at a higher price.")

customers remain indifferent to the purchase of QF power. The modification requested by the Company in this application is necessary to maintain this ratepayer indifference standard and is a means by which the Company and the Commission can protect customers from unnecessary fixed-price risk.

Q. Does the Commission have discretion to determine the appropriate contract term 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 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]

Q, Have other state commissions in the Company's service area recently addressed this issue?

A. Yes. The Idaho Public Utilities Commission (the "Idaho Commission") has recently addressed the need to reduce QF contract terms to protect ratepayer

[11] *Idaho Power Co.*, 316 P.3d at 1280; *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).

neutrality. Initially, the Idaho Commission set PURPA contract terms at 35 years to match the amortization period allowed for similar utility owned facilities, making financing easier, thus encouraging QF development.[14] Later, the Idaho 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 strategies.[16] The Idaho 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 Idaho 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 Idaho Commission's 1996 and 1997 orders reducing the term to five years, *i.e.*, the current concerns flow from the magnitude

[14] *See, e.g.* Case No. GNR-E-02-1, Order No. 29029 (Ida. PUC May 21, 2002) at 2 (describing the origin of PURPA regulation in Idaho).
[15] Case No. U-1500-170, Order No. 21630 (Ida. PUC Dec. 2, 1987).
[16] Case No. GNR-E-02-1, Order No. 29029 (Ida. PUC May 21, 2002) (describing the history of changes in approved term of QF contracts in Idaho).
[17] Case No. IPC-E-95-9, Order No. 26576 (Ida. PUC Sept. 4, 1996) p. 13.
[18] *See* Case No. GNR-E-02-1, Order No. 29029 (Ida. PUC May 21, 2002) p. 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.").

of QF power flowing onto utilities' systems without any finding of utility need and resulting concerns about price risk, reliability, and customer indifference. As a result, the Idaho Commission has recently reduced the term of PURPA contracts for the Company, Idaho Power and Avista to five years for solar and wind QF projects larger than 100 KW pending completion of a docket considering a permanent reduction.[19]

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 unusually long-term transaction, or to the QF to account for the price certainty the QF enjoys from such a contract. As noted above, this Commission has recognized that the avoided cost rates are not the only term of a power purchase contract with a QF that can affect the required ratepayer neutrality.[20] Contract lengths are also PURPA contract terms, and they carry with them their own economic value. To grant QFs access to long-

[19] Case No. IPC-E-15-01, Order No. 33222 (Ida. PUC Feb. 6, 2015) (Idaho Power), Order No. 33250 (Ida. PUC Mar. 13, 2015) (Rocky Mountain Power and Avista), and Order No. 33253 (Ida. PUC Mar. 18, 2015) (clarifying that the interim reduction applies to QF projects that exceed the published rate eligibility cap (up to 100 KW for solar and wind and up to 10 average megawatts (aMW) for QFs of all other resource types)).
[20] *See* footnote 10.

term price certainty with no adjustment to the price to account for that certainty is granting QFs something no other market participant enjoys. For this reason, I would view a guaranteed, fixed-price, 20-year contract at avoided cost to be a QF subsidy.

Q. Is there evidence that supports the Company's requested modification?

A. Yes. My testimony presents substantial and compelling evidence demonstrating why the Company's requested modification is necessary in order to maintain the "ratepayer indifference" standard.

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 145 PURPA contracts totaling 1,991 MW of nameplate capacity across its six-state system. Of this total, 101 projects totaling 1,814 MW (91 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, 51 projects totaling 1,145 MW (58 percent 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 Utah, 24 new projects totaling 897 MW have been executed in the last two years.

This dramatic increase in PURPA contract executions and pricing requests in Utah and system-wide in the last several years demonstrates that additional review of the contract term for non-standard Utah 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 Utah and across PacifiCorp's system.

A. In Utah, the Company currently has 40 project requests totaling 2,253.2 MW of nameplate capacity. System-wide, the Company currently has requests from 85 projects totaling 3,692.5 MW of nameplate capacity. 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	1	20.0	20	511.0	2	4.8	23	535.8
Oregon			12	250.9	1	3.5	13	254.4
Utah	5	354.0	35	1,899.2			40	2,253.2
Washington								
Wyoming	9	649.1					9	649.1
TOTAL	**15**	**1,023.1**	**67**	**2,661.1**	**3**	**8.3**	**85**	**3,692.5**

Exhibit RMP___(PHC-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 Utah PURPA contracts and proposed Utah PURPA contracts compare to PacifiCorp's typical Utah load requirements?

A. PacifiCorp has 1,041 MW of existing PURPA contracts in Utah and 2,253 MW of proposed PURPA contracts in Utah, together totaling 3,294 MW of nameplate capacity. Using 2014 as an example, PacifiCorp's maximum total retail load in

Utah was 5,073 MW, its minimum load was 2,033 MW, and its average load was 2,959 MW. The 3,294 MW of existing and proposed PURPA contracts in Utah at their nameplate capacity would be enough to supply 111 percent of the Company's average Utah retail load and 162 percent of the Company's minimum Utah 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 1,991 MW of existing PURPA contracts and 3,692 MW of proposed PURPA contracts, together totaling 5,683 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 5,683 MW of existing and proposed PURPA contracts at their nameplate capacity would be enough to supply 83 percent of PacifiCorp's average retail load and 114 percent of PacifiCorp's minimum retail load.

THE COMPANY'S UTAH 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."[21]

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

Q. Why is it critical to make the needed modification to QF contract term quickly once it has been identified?

A. As mentioned earlier in my testimony, PacifiCorp currently has 1,041 MW of existing PURPA contracts in Utah and 2,253 MW of proposed PURPA contracts in Utah, together totaling 3,294 MW of nameplate capacity. The Company has 145 existing (executed) PURPA contracts totaling 1,991 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. Utah's allocated share is typically around forty-three percent. The expected system-wide costs (payments to QFs) over the next 10 years from PacifiCorp's executed PURPA contracts is $2.9 billion. In 2015 alone, the projected payment to QFs is $170.5 million, with Utah's allocated share at $73.3 million.[22] If QF projects are priced higher than the market alternative by just 10 percent, it would create a $7.33 million impact in 2015 for Utah customers. That 10 percent impact would grow to a total of $124.7 million in additional costs to Utah customers over the 10-year period starting in 2015. With a pricing queue that currently totals 3,693 MW, or

[21] *Southern Cal. Edison Co., San Diego Gas & Elec. Co.*, 71 FERC ¶ 61,269 at p. 62,080 (1995).
[22] Assuming an allocation factor of 43 percent.

close to double (in MW) the size of the $2.9 billion worth of current PURPA contracts to which the Company is already obligated, it is imperative that customers be protected from the long-term, fixed-price risk that comes with a 20-year contract term for QFs. Failure to implement the modification to contract term proposed by the Company in this case may result in significant irreversible harm to customers.

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 collaborative convened as the result of concerns expressed by the Utah Division of Public Utilities ("Division"), the Utah Office of Consumer Services ("Office") and various other parties during proceedings on the Company's application for an energy cost adjustment mechanism,[23] a proceeding on management of natural gas price risk,[24] and its 2009 and 2011 general rate cases[25] regarding the Company's hedging program. In its report on the collaborative, the Division stated:

> All parties agree that the forecast total requirement for natural gas should not be fully hedged and a portion should remain open to short-term market price exposure and for operational flexibility. . . . Because of relative market illiquidity and potential inaccuracy of forecasted demand requirements, hedges should normally be limited to 36 forward months, except to the extent fundamental market analysis, including liquidity, support longer-

[23] *See* Docket No. 09-035-15.
[24] *See* Docket No. 09-035-21
[25] *See* Docket Nos. 09-035-23 and 10-035-124.

term purchases and acquisitions.[26]

The Company's trading policies and procedures are outlined in the PacifiCorp Risk Management Policy. That policy was modified based on the results of the collaborative process. It 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 energy management organization (formerly known as the commercial and trading organization) 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 the Company 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

[26] Collaborative Process To Discuss Appropriate Changes To PacifiCorp's Hedging Practices - Report to the Utah Public Service Commission (Mar. 30, 2012) at 6.

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 on terms set forth by its 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. Can you provide an example showing the inconsistency between the Company's hedging policies and its PURPA contracting requirements?

A. Yes. The Company cannot (without specific stakeholder interest and review) enter into a 20-year hedge for the natural gas fuel cost at one of its gas plants, such as Lakeside. But the Company is mandated to enter into a 20-year contract, with a fixed-price hedge, with a QF who may be displacing or avoiding the operation of that very same gas plant, effectively locking in the price of that output for 20 years.

The 20-year QF contract term is not consistent with the hedging policy put in place as a direct result of input from stakeholders.

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[27] review of the process and ultimate results. In Utah, if the resource or transaction involves a generating resource that produces 100 MW or more or has a term of 10 years or more that will produce 100 MW or more, the Company is required to go through this process.[28] 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 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 change necessary to protect customers.

Q. Why is such a rigorous review process necessary when entering into long-term

[27] An independent evaluator is a third party who is appointed by the Company's regulators to oversee the RFP process to ensure fairness throughout the process and to ensure the bids are accurately evaluated. *See, e.g.*, Utah Code Ann. § 54-17-203.
[28] *See* Utah Code Ann. §§ 54-17-101, et seq.

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 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 IRP, 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 RFP 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 10-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 10-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 10-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 10-year example, the Company currently has 2,253 MW of proposed PURPA contracts in Utah 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 the Company should lock in as much energy as possible?

A. Locking in a price because you are speculating that the price is "low" is not risk management or hedging – it is speculative trading. The Company and its customers are not commodity traders. The Company's 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 145 PURPA contracts totaling 1,991 MW of nameplate capacity across its six-state system. Utah's allocated share of these contract costs averages approximately 43 percent. Over the next 10 years, the Company is under contract to purchase 44.6 million MWhs under its PURPA contract obligations at an average price of $64.13 per MWh. The average forward price curve for Mid-C over this same 10 years is $38.11 per MWh,[29] or a difference of $26.02 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.

[29] 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 20-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 an RFP.

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

A. The 2013 IRP, which until the recent filing of the 2015 IRP was the reference for avoided costs in Utah, 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's 2015 IRP has now been filed with the Commission. The 2015 IRP 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 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.

CONCLUSION

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

A. The Company is seeking implementation of a modification to the term of QF contracts. This change is necessary in order to maintain the ratepayer indifference standard required by PURPA and to protect Utah customers. Specifically, the Company is requesting an order from the Commission directing implementation of a 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.

The Company is seeking this 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 modifications to the Company's current Utah avoided cost contracts. As noted, PacifiCorp currently has pending requests for 2,253 MW of new PURPA contracts in Utah, in addition to the 1041 MW of existing contracts. By comparison, Rocky Mountain Power's minimum retail load in Utah in 2014 was 2,033 MW. Across its six-state system, PacifiCorp currently has 3,693 MW of new PURPA contract requests, in addition to the 1,991 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 QF PURPA contract terms.

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 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 fixed price transactions. 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. In the hedging collaborative workshop, stakeholders made it clear that they did not believe long-term gas hedges (and the corresponding long-term fixed-price risk) were in the best interest of customers. The 20-year maximum QF contract term goes against this conclusion reached by the collaborative stakeholders. For example, the Company cannot (without specific stakeholder interest and review) enter into a 20-year hedge for the natural gas fuel cost at one of its gas plants, such as Lakeside. But the Company is mandated to enter into a 20-year contract, with a fixed-price hedge, with a QF who may be displacing or avoiding the operation of that very same gas plant, effectively locking in the price of that output for 20 years. The 20-year QF contract term is not consistent with the hedging policy put in place as a direct result of input from stakeholders.

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 modification to the Company's current Utah avoided cost contract term is required at this time to maintain the ratepayer indifference standard required by PURPA and to protect Utah customers from ongoing harm.

Q. Does this conclude your direct testimony?

A. Yes.