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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Modification of Contract Term of PURPA Power Purchase Agreements with Qualifying Facilities	)	DOCKET NO. 15-035-___ **APPLICATION**

Rocky Mountain Power ("Rocky Mountain Power" or "Company") hereby submits its application ("Application") to the Public Service Commission of Utah ("Commission") requesting approval to modify the maximum contract term of prospective power purchase agreements ("PPAs") with qualifying facilities ("QFs") under the Public Utility Regulatory Policies Act of 1978 ("PURPA"). The Company seeks a reduction in the maximum term of its PPAs with QFs from 20 to three years. In support of the Application, Rocky Mountain Power states as follows:

I. INTRODUCTION

1. Rocky Mountain Power is a division of PacifiCorp. PacifiCorp is an Oregon corporation that provides electric service to retail customers through its Rocky Mountain Power division in the states of Utah, Wyoming, and Idaho, and through its Pacific Power division in the states of Oregon, California, and Washington.

2. Rocky Mountain Power is a public utility in the state of Utah and is subject to the Commission's jurisdiction with respect to its prices and terms of electric service to retail customers in Utah. The Company serves approximately 830,000 customers and has approximately 2,400 employees in Utah. Rocky Mountain Power's principal place of business in Utah is 201 South Main Street, Suite 2300, Salt Lake City, Utah 84111.

3. Communications regarding this filing should be addressed to:

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In addition, Rocky Mountain Power requests that all data requests regarding this filing be sent in Microsoft Word or plain text format to the following:

By email (**preferred**): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, Oregon 97232

Informal questions may be directed to Bob Lively, Utah Regulatory Affairs Manager at (801) 220-4052.

II. PURPA

4. 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.[1] 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."[2] 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.[3] 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.[4]

5. 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.[5] While the applicable statutes and rules are matters of federal law, PURPA gives state commissions

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

[2] 16 U.S.C. § 824a-3 provides in pertinent part:

> (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.

[3] 16 U.S.C. § 824a-3(d) provides 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.

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

[5] *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).

the responsibility of determining a utility's avoided costs as well as the terms and conditions of PURPA contracts.[6]

6. In 1980, the Commission initiated Docket No. 80-999-06 to address those matters. In that docket, the Commission recognized that utilities and their customers are not required to subsidize QFs to achieve PURPA's policy goals. The Commission 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.[7]

7. 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."[8]

III. COMMISSION AUTHORITY TO DETERMINE CONTRACT TERM

8. Although PURPA's federal mandate requires utilities to purchase QF power, PURPA gives state commissions the authority to protect retail customers from any unintended negative consequences of these mandatory purchases. State commissions also establish the key terms and conditions of PURPA contracts.[9]

9. FERC acknowledges states' wide discretion in crafting PURPA contract methodologies for PURPA contracts, asserting, "states are allowed a wide degree of latitude in

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[6] *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)).
[7] *In the Matter of the Implementation of Rules Governing Cogeneration and Small Power Production in the State of Utah*, Case No. 80-999-06, Report and Order (April 3, 1987), p. 4.
[8] *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).
[9] *Idaho Power Co.*, 316 P.3d at 1280; *Exelon Wind I, LLC*, 766 F.3d 380 (5th Cir. 2014).

establishing an implementation plan for section 210 of PURPA, as long as such plans are consistent with [FERC's] regulations."[10]

10. A critical element of the utility's must-purchase requirement under PURPA is the contract term. The term is critical because FERC generally requires a utility to lock in forecasted avoided cost rates for the entire contract term.[11] FERC has explained that it believes imperfections found in the avoided cost methodology should, if set correctly, balance out between overestimation and underestimations.[12] However, PURPA and FERC regulations are silent as to the length of QF contracts and, with a few exceptions not relevant here,[13] FERC has not spoken directly to the issue of setting an appropriate contract length.

11. Under PURPA, states are tasked with assessing the needs of the state, the idiosyncrasies of the local utility systems, and the reliability and quality of potential power sources.[14] And it is the states that are implementing standards within FERC's PURPA framework in a manner consistent with the public interest.

12. This Commission has recognized that the term of a PURPA contract and the rates to be paid under that contract are interrelated.[15] 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 modification of contract term requested by the Company in this application is

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[10] *Cal. Pub. Util. Comm'n*, 133 FERC ¶ 61,059 at P 24 (2010).
[11] *See Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of PURPA*, 45 Fed. Reg. 12214, 12224 (1980).
[12] *Id.*
[13] For example, FERC has stressed a need for certainty with regard to return on investment in new technologies and for allowing for varying contract lengths based on other contract factors. *See, e.g., Cal. Pub. Util. Comm'n*, 133 FERC ¶ 61,059.
[14] *See FERC v. Mississippi*, 456 U.S. 742, 767 (1982) (explaining that PURPA "establishes a program of cooperative federalism that allows the States, within limits established by federal minimum standards, to enact and administer their own regulatory programs, structured to meet their own particular needs.").
[15] *In the Matter of the Implementation of Rules Governing Cogeneration and Small Power Production in the State of Utah*, Case 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.").

necessary to maintain ratepayer indifference and is a means by which the Company and the Commission can protect customers from unnecessary long-term, fixed-price risk.

IV. NEED FOR REDUCTION IN CONTRACT TERM

A. Dramatic Increase in QF Pricing Requests

13. The Company has experienced a dramatic increase in QF pricing requests in recent years. In Utah, of the Company's current 1,041 MW of QF contracts, contracts for projects totaling 896 MW (86 percent of the total PURPA MW under contract) have been executed in the last two years. System-wide, of the Company's 1,991 MW of QF contracts, projects totaling 1,145 MW (58 percent of the total PURPA MWs under contract) have online dates of 2014 or later.

14. The magnitude and potential impact of this increased PURPA activity may also be illustrated by comparing the total amount of existing and proposed Utah PURPA projects to the Company's Utah retail load. The Company currently has 2,253 MW of proposed PURPA contracts in Utah. This, combined with its 1,041 MW of existing PURPA contracts, totals 3,294 MW of nameplate capacity. In 2014, the Company's average Utah retail load was 2,959 MW and its minimum 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.

15. Expanding the foregoing analysis to the Company's six-state system, the Company currently has requests for 3,692 MW of new PURPA contracts system-wide, in addition to the 1,991 MW of QF contracts that are already executed. In 2014, the Company's average system-wide retail load was 6,844 MW and its minimum system-wide retail load was 4,967 MW. The 5,683 MW of existing and proposed PURPA contracts at their nameplate capacity would be enough to supply 83 percent of the Company's average retail load and 114 percent of the Company's minimum retail load.

B. Current Lack of Need for System Resources

16. The Company's long-term planning and resource decisions are thoroughly evaluated through the Company's Integrated Resource Plan ("IRP") process. The Company's IRP is developed with participation from public stakeholders, including the Commission and its staff, the Division of Public Utilities ("Division"), the Office of Consumer Services ("Office"), 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.

17. The Company would not plan to enter into long-term transactions unless a long-term resource need is identified in the IRP preferred portfolio. 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.

18. The Company's 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 did not develop 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.

19. Thus, while the Company has had a sharp increase in pricing requests for new PPAs with QF's under PURPA equal to 3,693 MW system-wide and 2,253 MW in Utah, the 2015 IRP indicates that the Company has no need for any system resource until at least 2028.

C. Potential Impact of QF Contracts on Customers

20. The Company has 145 existing (executed) PURPA contracts totaling 1,991 MW of nameplate capacity across its six-state system. Under the Company'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 ten years from the Company'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.[16] 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 ten-year period starting in 2015. With a pricing queue that currently totals 3,693 MW, or 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

[16] Assuming an allocation factor of 43 percent.

customers be protected from the long-term, fixed-price risk that comes with a 20-year contract term for QFs.

21. 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 the Mid-Columbia wholesale power market trading hub over this same ten years is $38.11 per MWh,[17] or a difference of $26.02 per MWh. This fact further illustrates that the current 20-year contract term for QFs exposes customers to unreasonable fixed-price risk.

D. Inconsistency of 20-year Term with Hedging Collaborative and Contracting Policies and Practices

22. The current 20-year term of QF PPAs is inconsistent with the Company's risk management policies resulting from the 2011-2012 hedging collaborative. The collaborative was prompted by concerns raised by the Division, the Office and other customer representatives and interest groups regarding hedging in several Utah dockets.[18] During the collaborative, stakeholders urged the Company to reduce its hedging horizon for electricity and gas from 48 to 36 months unless stakeholders express an interest for longer term hedges based on fundamental market analysis.

23. 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 QF contract term is inconsistent with this conclusion reached by the collaborative stakeholders. For example, the Company cannot (without specific stakeholder

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

[18] *See* Docket Nos. 09-035-15 (ECAM), 09-035-21 (Natural Gas Price Risk), 09-035-23 (2009 General Rate Case), 10-035-124 (2011 General Rate Case).

interest and review) enter into a 20-year hedge for the natural gas fuel cost at one of its gas plants, but the Company is mandated under current Commission orders 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.

24. 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.

25. Non-PURPA transactions that exceed 36 months in effective transaction period require extensive analysis and progressively higher level of management review the longer their term. 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.

26. 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.

27. 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.[19] 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 enjoys.

E. Inconsistency of 20-year Contract Term with Acquisition of Least-cost, Least-risk Resources

28. 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 to serve load, so it contracts to buy the output from a certain generator). Most of these long-term transactions occur through rigorous, transparent, and competitive request for proposals processes.

29. The current 20-year contract term is inconsistent with Utah law requiring the Company to ensure the acquisition of least-cost, least-risk resources.[20] Locking in contract rates for 20 years exposes the Company and its customers to unreasonable long-term, fixed-price risk.

[19] *See* footnote 15.
[20] *See, e.g.* Utah Code Ann. § 54-17-302(3)(b).

30. Furthermore, a 20-year term is inconsistent with the Company's IRP planning process. The Company files IRPs every other year and updates the IRPs during alternate years. As discussed above, in recent years, IRPs have consistently indicated that the Company has no current need for long-term resources. In addition, the anticipated need for such resources has extended farther into the future with each successive IRP. The current IRP indicates that no long-term resource will be needed until 2028. Yet, contrary to sound planning, the Company is currently required under PURPA and the Commission's decisions to enter into PPAs with QFs for a term of 20 years.

31. The full IRP is published every other year, with an update published in the off years. 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 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.

32. 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.

V. SUPPORTING EVIDENCE

33. This Application and the requests made herein are further supported by the written direct testimony and exhibit of Mr. Paul H. Clements filed herewith.

VI. CONCLUSION

34. 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 from unreasonable long-term, fixed-price risk.

35. The Company is seeking this modification at this time 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 Utah avoided cost contracts. As noted, PacifiCorp currently has pending requests for 2,253 MW of new PURPA contracts in Utah and pending requests for 3,693 MW of new PURPA contracts across its six-state system. 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.

36. Given this exponential increase in QF contracting activity, it is critical to quickly adjust the maximum contract term from 20 years to three years. 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.

37. 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 is inconsistent with this conclusion reached by the collaborative stakeholders.

38. Transactions that exceed 36 months require extensive analysis and progressively higher level of management review. The primary reason that 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 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 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.

39. 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.

RELIEF REQUESTED

Based on the foregoing, the Company requests that the Commission:

a. notice a scheduling conference at the earliest available time to establish a schedule for proceedings on this Application; and

b. approve the Company's request for a permanent reduction in the maximum contract term for PURPA QF contracts, from 20 years to three years.

Dated: May 11, 2015.

Respectfully submitted,
ROCKY MOUNTAIN POWER

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