# 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. 15-035-53**

i

**The Sierra Club**

**Direct Testimony of R. Thomas Beach**

# September 16, 2015

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# EXECUTIVE SUMMARY

Rocky Mountain Power (“RMP” or “the Company”), a unit of PacifiCorp, has filed an Application asking the Commission to reduce from 20 years to three years the maximum term of power purchase contracts with large renewable generation projects developed in its service territory, projects which are qualifying facilities (QFs) under the Public Utilities Regulatory Policies Act (PURPA). The Company is concerned that, if the 20-year term is retained, it may have to execute up to 2,253 MW of additional contracts with renewable QF projects, mostly solar and wind, which presently have been proposed to be developed in its Utah service territory. The utility has expressed concerns with the lack of need and the potential costs to its ratepayers of this additional renewable generation.

The Sierra Club opposes RMP’s Application. First, RMP is essentially asking the Commission to interfere with a functioning free market that was expressly designed to counter the overwhelming market power of the utility. It is clear that the intent of the utility’s request is to make it impossible to finance additional renewable projects in its service territory. Capital-intensive solar and wind projects cannot be financed with three- year contracts. It is questionable whether such a step complies with the legal requirements of PURPA to encourage the development of qualifying renewable generation that can be developed at the utility’s avoided costs. If RMP does not want to comply with its PURPA obligations, there are well-established ways for the utility to replace its traditional PURPA obligation and for the state of Utah to assume greater control over utility procurement of renewable generation in the state. However, these alternative means may require significant changes to the energy markets in Utah.

Second, the prices in PURPA contracts are set based on the utility’s avoided costs, that is, on the costs that the utility would incur for the same amount of power if it did not purchase the PURPA generation. As a result, RMP’s ratepayers will be indifferent, on a forecast basis, to the purchase of the additional solar generation. The utility claims that it is too risky and unnecessary to make these long-term commitments. This testimony responds to these arguments, and shows that this fixed-price renewable generation will offer significant benefits to RMP’s ratepayers, benefits that are not included in the avoided cost price they will pay for the power, including:

* **Low-priced solar generation.** There is a limited window of opportunity for RMP to purchase low-cost solar generation before the 30% federal investment tax credit expires at the end of 2016.

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* **REC sales revenues.** RMP and PacifiCorp will gain additional revenues from the sale of the renewable energy credits (RECs) that RMP may negotiate to acquire along with this power, or, alternatively, from reduced costs to comply with future regulations requiring certain levels of renewable generation in PacifiCorp’s portfolio or limiting the carbon emissions from PacifiCorp’s system.
* **Hedging benefits.** Fixed-price power hedges against future volatility in energy market prices. Such a hedge is generally considered to be a benefit for consumers.
* **Lower market prices.** Zero-variable-cost renewable generation will reduce energy market prices in the West generally.
* **Capacity options.** The solar generation will provide a new capacity option that will have value if existing coal-fired capacity is retired earlier than expected.
* **Economic development.** The potential solar projects represent an investment of billions of dollars in clean energy infrastructure in the state of Utah over the next several years. Even if only a fraction of these projects are developed, they would provide Utah with the economic benefits associated with this new development of modern clean energy facilities. If these projects are not built in Utah, they could be developed in one of the surrounding states that are also rich in renewable resources.

This testimony quantifies each of the above benefits. These significant benefits, combined with the avoided cost pricing for the additional solar generation, mean that this generation will offer significant net economic benefits to energy consumers in Utah, regardless of whether this renewable generation serves Utah consumers or, as a result of the sale of the associated RECs, helps neighboring states to comply with their renewable portfolio standards.

The Sierra Club also addresses any concerns that the Commission may have with the system reliability impacts of additional solar generation. Significant studies have been conducted in recent years of the operational and reliability impacts of integrating high levels of wind and solar generation on the Western Electricity Coordinating Council (WECC) grid. A much higher penetration of solar generation is feasible in the WECC than what would result from these solar contracts. Changes in the energy markets in the WECC already are underway to facilitate renewables integration, such as the energy imbalance market that began operations in November 2014 and in which PacifiCorp is a leading participant.

iii

Finally, The Commission’s method for setting avoided cost prices provides the utility with the ability to update its forward price curve for its avoided costs, in order to reflect changing loads & resources, natural gas prices, and the need for generation. Moreover, as RMP adds more renewable QF generation, its avoided cost prices are dropping as this generation replaces progressively less expensive power. This can be seen in the declining indicative prices that RMP has provided to solar projects in its pricing queue. These indicative prices, when compared on an apples-to-apples basis with the lowest public PPA prices for solar in the western U.S., show that none of the solar QFs in RMP’s queue are likely to be successfully developed at the indicative prices. Furthermore, even among the projects that have secured a contract with RMP or PacifiCorp, there is no guarantee that the project will be successfully sited, obtain financing, complete construction and interconnection, and come on-line. This is particularly true at this moment for solar projects, given the time pressure of the step- down at the end of 2016 of the 30% federal investment tax credit for solar. This data and circumstances demonstrate that there is no present crisis with an oversupply of renewable QFs in Utah, such that the Commission needs to shorten the QF contract term to a length that will no longer encourage the development of solar and wind QFs in Utah.

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1. I. INTRODUCTION

# Q: Please state your name, address, and business affiliation.

1. **A:** My name is R. Thomas Beach. I am principal consultant of the consulting
2. firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 213A,
3. Berkeley, California 94710.

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# Q: Please describe your experience and qualifications.

1. **A:** I have over 30 years of experience in utility analysis, resource planning,
2. and rate design. I began my career at the California Public Utilities Commission,
3. working from 1981-1984 on the initial implementation in California of the Public
4. Utilities Regulatory Policies Act (PURPA) of 1978. I then served for five years as
5. an advisor to three CPUC commissioners. Since entering private practice as a
6. consultant in 1989, I have served as an expert witness in a wide range of utility
7. proceedings before many state utility commissions. This includes sponsoring
8. testimony on PURPA-related issues in state regulatory proceedings in California,
9. Idaho, Oregon, Nevada, North Carolina, and Vermont. Prior to this experience, I
10. earned degrees in English and Physics from Dartmouth College and a Masters in
11. Mechanical Engineering from the University of California, Berkeley. My
12. curriculum vita is attached to this testimony as Exhibit SC-1.

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# Q: On whose behalf are you testifying in this proceeding?

1. **A:** I am appearing on behalf of the Sierra Club.
2. The Sierra Club is a national, non-profit environmental and conservation
3. organization dedicated to the protection of public health and the environment.
4. Sierra Club is participating in this matter on behalf of itself and the approximately
5. 3,800 Sierra Club members who live and purchase utility services in Utah. Sierra
6. Club's Utah members have a direct and substantial interest in this proceeding as
7. a result of its potential impact on additional solar deployment in Utah and on the
8. environmental, health and economic benefits that would result from the addition
9. of this renewable generation to PacifiCorp’s electric system in Utah.

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# Q: Have you previously testified or appeared as a witness before the

1. **Public Service Commission of Utah?**
2. **A:** No, I have not. However, I recently testified on a similar issue before the
3. Idaho Public Utilities Commission, of behalf of the Sierra Club and the Idaho
4. Conservation League (Case No. IPC-E-15-01 *et al.*).

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# Q: Do you have any exhibits?

1. **A:** Yes. Exhibit SC-1 is my curriculum vitae. Exhibit SC-2 includes certain
2. discovery responses from RMP.
3. II. BACKGROUND ON PURPA

# Q: RMP’s Application generally describes the requirements of PURPA.

1. **Do you have anything to add to this background?**
2. A: Yes. As a consultant with over 30 years of experience in PURPA-related
3. issues, I offer the following economic perspective. Congress enacted PURPA to
4. encourage a new, free market for the independent development of generation
5. from resources that would reduce our nation’s dependence on fossil fuels, with
6. the goal of increasing the energy security and independence of the United
7. States. PURPA required public utilities, who enjoyed a state-sponsored
8. monopoly in the generation market, to purchase power from cogeneration and
9. small renewable power producers, collectively called “qualifying facilities” or QFs,
10. at prices that could not exceed the utilities’ “avoided cost.” In the words of the
11. statute, avoided costs are “the cost to the electric utility of the electric energy
12. which, but for the purchase from such cogenerator or small power producer, such
13. utility would generate or purchase from another source.”[1](#_bookmark0) PURPA’s must-take
14. requirement at an avoided cost price was intended to offset the monopsony
15. power[2](#_bookmark1) of the utility as the sole buyer of generation in its service territory.
16. Congress limited purchase price to the utility’s avoided cost in order to achieve a
17. balance between the interests of ratepayers and PURPA generators, so that the
18. price would be both “just and reasonable to the electric consumers of the electric

1 Section 210(d) of PURPA (92 Stat. 3117, 16 U.S.C. § 2601).

2 A monopsony market is similar to a monopoly except that a large buyer, not a large

seller, controls a large proportion of the market and drives the prices down. A monopsony is sometimes also referred to as the buyer's monopoly.

1. utility and in the public interest” and “not discriminate against qualifying
2. cogenerators or qualifying small power producers” in comparison to the utility’s
3. other supply options. The FERC and the courts have found that a price set at
4. 100% of the utility’s avoided cost satisfies this dual standard and the intent of
5. PURPA to encourage QF development.[3](#_bookmark2) In essence, the economic design of
6. PURPA was to simulate the outcome of a free and open market that would
7. encourage QF development, if QFs could offer generation at a competitive cost
8. equal to or less than the incremental cost to the utility of procuring power from
9. other sources. PURPA generation purchased at the avoided cost price would be
10. reasonable for the consumer because it would be no more expensive than if the
11. monopoly utility had generated the power itself or purchased it from another
12. source.

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# Q: PURPA was enacted almost four decades ago. Have Congress and

1. **the FERC enacted significant changes to PURPA since then?**
2. A: Yes. PURPA was the key first step in the development of independent
3. power generation in the U.S. The success of this new industry in many states
4. under the PURPA framework enabled the creation, in the 1990s and early 2000s,
5. of viable and less-regulated markets for electric generation in many regions of
6. the U.S. Over time, these markets have expanded to include, in some states,
7. competition in generation at both retail and wholesale levels, as well as non-

3 18 C.F.R. § 292.304(b)(2); *American Paper Inst., Inc. v. American Elec. Power Serv. Corp.*, 103 S. Ct. 1921 (1983).

1. discriminatory access to electric transmission through regional transmission
2. organizations (RTOs) with independent system operators of the transmission
3. grid. In addition, many states have enacted renewable portfolio standard (RPS)
4. programs, based on states’ traditional authority over utility procurement,
5. designed to provide long-term markets for the new renewable generation that
6. previously had been developed principally through PURPA. Responding to these
7. developments, Congress enacted the Energy Policy Act of 2005 (EPAct), which
8. implemented a new Section 210(m) of PURPA. This section allowed a utility to
9. petition the FERC for relief from the “must purchase” requirement of PURPA if
10. FERC found that QFs in that utility’s territory have access to sufficiently
11. competitive wholesale markets for long-term sales of capacity and electric
12. energy.

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# Q: Have utilities in other states and regions successfully petitioned the

1. **FERC under Section 210(m) of PURPA to end the PURPA must-purchase**
2. **obligation?**
3. A: Yes. However, this has occurred in states that have opened their
4. generation market to substantial competition at the wholesale level. For example,

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when the major California investor-owned utilities (IOUs) successfully petitioned

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the FERC for relief from the PURPA must-purchase obligation for QFs larger

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than 20 MW, they were able to show that California had taken the following steps

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to provide viable long-term wholesale markets for QF generation:

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* A CPUC-approved program for the IOUs to conduct competitive solicitations for long-term contracts (with terms of 7 to 12 years) with at least 3,000 MW of existing or new cogeneration (also known as combined heat and power or CHP) QFs;
* A state-enacted RPS that required the California IOUs to purchase a specified percentage of their generation from RPS-eligible renewable generators by a date certain (originally 20% by 2017, then 20% by 2010, now 33% by 2020, and soon to be 50% by 2030), implemented through regular competitive solicitations to procure RPS generation under long-term contracts of up to 25 years;
* A resource adequacy program requiring the IOUs to purchase capacity from QFs and merchant generators to meet near-term resource adequacy requirements; and
* Non-discriminatory access to the transmission system and to an auction-based, day-ahead wholesale energy market operated by a FERC-regulated RTO, the California Independent System Operator (CAISO).[4](#_bookmark3)

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It is important to note that the PURPA must-purchase obligation remains in place

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in California (and in most other RTO/ISO footprints) for QFs up to 20 MW in size,

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and that the must-purchase obligation can be re-instated if the FERC finds that

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long-term wholesale markets are no longer available to QFs. The fact that the

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U.S. Congress and the FERC have found that a state must create long-term

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wholesale markets for energy and capacity from QFs in order to end PURPA’s

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must-purchase obligation indicates clearly that the fundamental purpose of the

4 *Pacific Gas & Electric et al,*, 135 FERC ¶ 61,234 (issued June 16, 2011).

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PURPA program continues to be to provide such a long-term market for QF

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generation.

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# Q: It has been asserted that the RTOs in which the PURPA must-

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# purchase obligation has ended do not provide markets for wholesale sales longer than three years.[5](#_bookmark4) Do you agree with this argument?

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A: No. The flaw in this argument is that the key feature necessary to end the

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PURPA must-purchase obligation is that renewable and cogeneration resources

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must have access to long-term power purchase agreements. These new long-

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term markets are based on procurement programs, principally RPS programs,

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sponsored by the states under their authority over utility procurement, not

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through the RTOs. Again, the California RPS program noted above is an

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example of such a state-sponsored RPS program that provides long-term

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contracting opportunities for renewable QFs in California. 29 states have RPS

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programs, and an additional 8 states (including Utah) have less stringent

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renewable portfolio goals; the states whose utilities operate within RTOs and

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have deregulated wholesale markets are generally included within these 37 states.[6](#_bookmark5)

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# Q: How has RMP described its PURPA obligations as they relate to

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# long-term planning?

5 *See* the testimony of William H. Hieronymous, on behalf of Idaho Power, before the Idaho Commission in Case No. GNR-E-11-03.

6 *See* [www.dsireuse.org](http://www.dsireuse.org/) website data on RPS programs.

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A: RMP asserts that it is not allowed to consider need in acquiring PURPA

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resources, and that it must purchase long-term QF generation that it does not

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need. The Company complains that QFs are not subject to the comprehensive

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planning process by which it identifies long-term needs in its biennial Integrated Resource Plan (IRP) process,[7](#_bookmark6) although I see no reason that the Company could

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not consider possible QF generation that is likely to be available at avoided cost

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prices as a resource option in its IRPs, in the same way that it considers other

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sources of market-priced generation.

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# Q. How does RMP Propose to address this issue?

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A: The Company is essentially asking the Commission to interfere in the

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functioning QF market. If approved, RMP’s application would prevent most future

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PURPA contracts in Utah, particularly for renewable QFs, by shortening the

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contract term in a manner that would almost certainly prohibit renewable QF

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developers from obtaining financing. Instead of the draconian step of shortening

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the term of QF contracts, which would close the long-term wholesale market for

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renewable QF resources in Utah, there are other steps Utah could take to allow

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greater control over the acquisition of renewable resources.

7 Application, at p. 27; Clements testimony, at pp. 23-25.

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# Q: What other steps could Utah take in order to allow the state greater

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# control over its acquisition of renewable resources?

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A: RMP is seeking a substantial change in the state’s competitive energy

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market. This type of statewide change in the energy market could and should

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follow the direction of the Utah Legislature. Unless and until the Legislature acts

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on this issue, the Commission should refrain from initiating on its own the

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substantial market changes suggested by RMP. If the Utah Legislature

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determines it should act to try to relieve RMP of its PURPA obligation, it could

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allow the state to take more direct control of renewable development by changing

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its 2025 renewables goal to a full-fledged RPS program that requires the

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procurement of new long-term renewable resources for Utah, perhaps with

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intermediate, near-term goals prior to 2025. This would allow RMP to show the

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FERC that the state has created a long-term wholesale market for additional

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renewable generation to serve consumers in the state. This showing would be

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important if the state’s utilities were to petition the FERC for relief from the

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PURPA must-take requirement under Section 210(m), as it was for the California

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utilities.

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More generally, an RPS would provide an outlet for renewable

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development that is under direct state control by the Legislature and the

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Commission. For example, in California, each year a regulated utility must submit

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an RPS Procurement Plan to the California PUC for approval; these plans set

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forth in comprehensive detail – comparable to an IRP – how the utility will

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procure adequate renewable generation to meet the RPS program goals. The

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California utilities procure RPS power under long-term contracts using detailed,

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competitive requests for proposals (RFPs) that are fully comparable to the

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process that RMP follows in Utah to procure long-term resources. These plans

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and RFPs provide the state with comprehensive oversight over renewable

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development in California – exactly the type of planning control that states may

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lose from the federal PURPA must-purchase mandate. Furthermore, in a state

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that has an RPS program, when the RPS goal is reached, renewable developers

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and proponents need to ask the state legislature or regulatory commission to

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increase the program target. For example, this has already occurred several times in California, as successive RPS goals have been reached.[8](#_bookmark7) Under this

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approach, control over renewable development largely passes to the state, and

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away from the federal PURPA requirements. Although a state RPS does not

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automatically allow a utility in that state to avoid the PURPA must-purchase

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obligation, it would make it more difficult for a would-be QF to assert to the FERC

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or the federal courts that the utility has not done enough to promote QF

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development, if the utility was in compliance with the state’s RPS program.

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Further, as noted above, an RPS can be an integral part of a showing under

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Section 201(m) of PURPA to end the must-purchase obligation.

8 California’s initial RPS goal, enacted in 2004, had a goal of 20% renewable generation by 2017. This goal was later advanced to 20% by 2010, and then increased to the current 33% by 2020. The California Legislature has just passed a further increase to 50% by 2030 (SB 350), and Governor Jerry Brown is expected to sign it. California’s investor-owned utilities acquire RPS resources through regular competitive solicitations in which new renewables are procured under the dual standards of (1) least-cost and (2) best-fit to the needs of the utility.

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Finally, an RPS would allow Utah consumers to benefit directly from the

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renewable development that has already occurred in the state, and that could

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continue in the future. Because Utah’s renewable program includes only a goal

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for 2025, without a more stringent RPS program with intermediate goals, and

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because the Company either does not acquire or sells the renewable energy

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credits (RECs) associated with the renewable resources that it purchases, RMP

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cannot and does not claim that it serves its customers with this renewable

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generation.

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# Q: Has the state of Utah or the electric utilities serving Utah taken steps

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# that might allow it to petition FERC for relief from the PURPA must-

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# purchase requirements?

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A: I am not aware of any such steps that have been taken in Utah. RMP has

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gone straight to the Commission with its request to impose limits on what is

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currently a functioning market for long-term wholesale renewable power. In my

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judgment, most of these steps to substantially change the PURPA program in

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Utah would require the state to adopt a successor program, such as an RPS

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(instead of Utah’s current renewables goal), to provide a viable long-term

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wholesale market for QF generation, and also could require broader changes in

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the wholesale markets in Utah. Nonetheless, these options exist for greater state

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control over renewable resource development, and examples of how to pursue

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them are available in many other states with active RPS programs. However until

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Utah pursues such a course, the longstanding PURPA framework, including the

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must purchase requirement, will be a feature of the energy landscape in Utah,

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and the changes to Utah’s PURPA program that RMP is requesting in this docket

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must be assessed in terms of whether they satisfy the longstanding goal of the

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PURPA program to promote the development of QF generation at avoided cost

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prices.

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1. HISTORY OF QF DEVELOPMENT IN UTAH

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# Q: Paul Clements’ testimony presented information on the history of

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# the development of PURPA projects in Utah. What is your reaction to this

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# history?

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A: Most of the renewable QF projects successfully developed in Utah or in

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PacifiCorp’s multi-state service territory have obtained power purchase contracts

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with terms of at least 15 years. Of PacifiCorp’s 537 MW of existing operational renewable QF contracts that do not burn fossil fuels or biomass,[9](#_bookmark8) the weighted

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average contract term is 19.7 years. Specifically, 91% of this capacity operates

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under contract terms of 10 years or longer*.* 100% of the 897 MW of wind and

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solar contracts that PacifiCorp has signed in the last several years (but that are

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not yet on-line) have 20-year terms.

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This history is not surprising – renewable energy projects (except for

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biomass) have no fuel costs but are capital-intensive, and, in my decades of

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experience I have observed that long-term contracts are essential for such

9 In other words, QFs using all technologies except natural gas-fired cogeneration and biomass or biogas.

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projects to access financing on reasonable terms. This need for long-term

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assurance of capital recovery is the same for QFs as it is for a utility that

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proposes to build a new power plant and seeks Commission approval for long-

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term recovery of the plant’s costs by including them in rate base. A utility would

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not build a new generating plant if it were only assured of cost recovery through

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rate base for three years, and had to re-justify the plant’s cost-effectiveness

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every three years. This history shows that, without long-term, 20-year contracts,

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few if any QFs will be developed in Utah.

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1. THE TERM OF QF CONTRACTS IN OTHER STATES

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# Q: Have other states had similar experiences, in terms of the

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# relationship between QF development and the available contract term?

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A: Yes. Idaho provides one example. The following figure shows that virtually

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all of the QFs developed on the Idaho Power system date from periods when that

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state has allowed QF contracts of 20 years or longer.

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California offered 20- to 30-year PURPA contracts in the 1980s, with

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renewable QFs provided fixed energy and capacity prices for up to the initial ten

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years of the contract, and fixed capacity prices for the full contract term.

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Approximately 5,000 MW of renewable QF generation was developed in the state

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in the late 1980s; most of this capacity is still operating today and now is the

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lowest cost generation available to the state’s RPS program. This development

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ceased when the long-term contracts were suspended in the late 1980s (short-

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term contracts remained available), and did not revive until after the enactment of

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the California RPS program in 2004, which again offered the QF market long-

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term contracts of up to 25 years.

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Finally, the recent active development of solar QFs in North Carolina,

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Idaho, Utah, and Oregon has been founded upon the availability of 15-to-20 year

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contracts at known, fixed prices.

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# Q: Have any state utility commissions denied a utility request to reduce

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# the term of PURPA contracts?

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**A:** Yes. Last year the utilities in North Carolina asked the commission in that

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state to shorten the term of PURPA contracts to a maximum of 10 years, a

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reduction of 5 years from the maximum of 15-year term that in recent years has

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resulted in significant development of solar QFs in that state.

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The North Carolina Utilities Commission rejected the utilities’ request, finding that

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the term of QF contracts needs to be long enough to enable QF projects to be

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financed:

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While the Commission initiated this docket to investigate the need to alter avoided costs determinations, the evidence presented by the buyers and sellers of QF power fail to justify altering the Commission’s earlier decisions on term length and related provisions. As discussed earlier, a QF’s legal right to long-term fixed rates under Section 210 of PURPA is well established as a result of the FERC’s *J.D. Wind* Orders. The FERC has made clear that its intention in Order No. 69 was to enable a QF to establish a fixed contract price for its energy and capacity at the outset of its obligation because fixed prices were necessary for an investor to be able to estimate with reasonable certainty the expected return on a potential investment, and therefore its financial feasibility, before beginning the construction of a facility. In her responses to cross-examination questions about various Duke Energy Renewables projects, DEC/DEP witness Bowman acknowledged the

foregoing by stating that PURPA does not require the best financing, just the ability to secure it.[10](#_bookmark9)

10 North Carolina Utilities Commission, *Order Setting Avoided Cost Input Parameters* (Docket No. E-100 Sub-140, issued December 31, 2014), at pp. 19-20. Hereafter, “North Carolina Avoided Cost Order.”

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Conversely, utilities in Idaho, including RMP, asked the Idaho Commission

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earlier this year to reduce the maximum 20-year term of PURPA contracts to 2

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years. The circumstances in both North Carolina and Idaho – the utilities in both

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states strenuously claiming to be overwhelmed by solar QF development – are

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similar to those in Utah today. As described below, the North Carolina and Idaho

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commissions reached different conclusions when presented with this issue. The

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Idaho commission granted the request to shorten the contract term to two years.[11](#_bookmark10) The Idaho commission based its decision on the interpretation that

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PURPA does not require long-term contracts, and that a shorter contract term will

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better align the avoided cost prices in QF contracts with market prices and the utility’s actual avoided costs.[12](#_bookmark11)

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The Idaho commission did not address whether long-term contracts are

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necessary to allow QF projects to be financed; nor did the Idaho commission

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address the evidence on the significant ancillary benefits of QF resources, such

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as is presented in Section VI of this testimony. Finally, the Idaho PUC declined

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“to treat QFs similarly with utility resources,” and found Idaho’s past record of QF

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contracting showed that it had made “significant advancements” to “encourage the development of renewable resources.”[13](#_bookmark12) The Idaho order does allow a QF

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that signs a series of shorter-term contracts to retain the date of capacity

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deficiency that existed at the time of its initial contract, presumably allowing such

11 Idaho Public Utilities Commission, Order No. 33357 in Case No. IPC-E-15-01 *et al*., issued August 20, 2015.

12 *Ibid.*, at pp. 11-12 and 22-23.

13 *Ibid.*, at p. 24.

328

a QF to receive capacity payments after that date, if it remains under contract.

329

This recognizes that a QF would be likely never to reach a year of capacity

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deficiency if that date re-sets further into the future every time the QF signed a

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332

short-term contract, even though the QF may provide significant ongoing capacity to the utility.[14](#_bookmark13)

333

1. THE TERM OF QF CONTRACTS IN UTAH SHOULD NOT BE

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CHANGED.

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# Q: Should the Commission reject the Company’s proposal to reduce

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# from 20 years to three years the maximum term for prospective PURPA

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# contracts for QF projects?

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A: Yes. The proposed reduction in the maximum term for these QF contracts

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340

should be rejected, for the reasons presented below.

341

# Q: What is the first reason why RMP should continue to make a 20-year

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# contract available to QFs?

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A: Fundamentally, a contract term of this length is necessary to realize

344

PURPA’s policy goal of supporting QF development. The Company is correct

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346

that “[a] critical element of the utility’s must-purchase requirement under PURPA is the contract term.”[15](#_bookmark14) According to the Company, “[t]he term is critical because

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FERC generally requires a utility to lock in forecasted avoided cost rates for the

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entire contract term.” It is also critical because capital-intensive solar and wind

14 *Ibid.*, at pp. 25-26.

15 Application, at p. 5.

349

projects cannot be financed without long-term contracts. In fact, contract term is

350

a decisive factor in QF development. As discussed above, states have

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successfully encouraged the development of QFs when they have offered long-

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term (15-year to 35-year) contracts at known avoided cost prices. In contrast,

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when only short-term (5 years or less) contracts have been available, relatively

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few QFs are developed. The few QF projects that may be developed with

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shorter-term contracts are cogeneration and biomass QFs that have significant

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fuel costs; these QFs may prefer shorter-term contracts whose prices are more

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closely linked to the fuel markets which are the most important input cost for

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these technologies. The history of QF development cited above, including on the

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PacifiCorp system, fully supports this conclusion that renewable QFs (except

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perhaps for biomass) require long-term contracts to be successfully developed.

361

Developers of solar projects and other renewable QFs will not be able to

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obtain financing for their projects if all that they can show a lender is that they

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have a customer for the power for just the first three years of a 25-year project

364

life. In addition, a contract price that is based on just the next three years of

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avoided costs often will be lower than a price based on the next 10 to 20 years of

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expected avoided costs, because avoided cost are expected to increase over

367

time. For example, based on PacifiCorp’s current forward price curve for Mid-C,

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the current indicative average avoided cost price for a three-year solar contract is more than 25% below the average price for a 10-year contract.[16](#_bookmark15) As a result,

16 The Mid-C forward prices are in Rocky Mountain’s confidential response to Sierra Club Data Request 2.16. We assumed that a solar QF would avoid a Mid-C price

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limiting the term of QF contracts to three years would reduce significantly the

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contract price, thus making uneconomic QFs that might be developed at avoided

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cost prices with a long-term agreement. Without an RPS or other state-

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sponsored procurement program for renewable QFs, it becomes questionable

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whether RMP’s proposed three-year maximum term for PURPA contracts

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376

adequately supports QF development in its service territory, as PURPA requires.

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# Q: RMP raises the specter that its Utah system could be overwhelmed

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379

# with an additional 2,253 MW of unwanted QF generation, with costs approaching $6 billion.[17](#_bookmark16) Will the Commission’s current approach to

380

# setting avoided cost prices for long-term QF contracts result in unlimited

381

# QF development in Utah?

382

A: No. The Commission’s current pricing mechanism will act on its own

383

accord to limit QF development to what is economic for ratepayers. The

384

Commission’s current method used to set long-term avoided cost prices in Utah

385

allows the utility to update its avoided costs for each successive QF to reflect the

386

capacity deferral from previously-approved QF contracts. The Company also can

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update its avoided costs to reflect changes to its forward price curve, such as

388

389

changes to its fuel price and load forecasts that are used in calculating avoided cost prices.[18](#_bookmark17) The result of such updates to avoided costs is that the price in

weighted 6/7 by high load hour prices (Mondays-Saturdays) and 1/7 by low load hour prices (Sundays).

17 Clements testimony, at p. 14, lines 265-269.

18 RMP response to Sierra Club Data Request 2.2, included in Exhibit SC-2.

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solar contracts will decline as fuel cost and load forecasts are revised and as

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additional QF contracts are added.

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The market for QF power in Utah appears to be working in exactly this

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way. The indicative prices that RMP / PacifiCorp has quoted to the solar QFs in

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its pricing queue indicate that few, if any, of the solar projects in Utah that are

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now in the utility’s pricing queue can be economically developed at current

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indicative prices.

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The lowest 20-year solar PPA price in the western U.S. that has been

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made public this year is NV Energy’s contract with Sunpower for a 100 MW utility-scale PV project in Boulder City, Nevada, near Las Vegas.[19](#_bookmark18) The 20-year

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levelized price in this contract is $46.00 per MWh; the project is expected on-line

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by the end of 2016 to qualify for the 30% federal investment tax credit. This

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project is sited in a special zone for solar projects that is adjacent to major

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substations and has the advantage of a solar resource that will produce about

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12% to 26% more annual output than a comparable project in Utah. This

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indicates that the minimum 20-year levelized avoided cost price likely to be

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needed in Utah for a viable utility-scale solar project is in the range of $51 per

407

MWh (if located in the sunniest part of Utah [Cedar City]) to $58 per MWh (in Salt

19 NV Energy has filed for approval of this PPA from the Public Utilities Commission of Nevada in Docket No. 15-07-003. See the direct testimony of William K. Branch of NV Energy discussing the details of this PPA, esp. Exhibit Direct-Branch-2. In this docket, NV Energy also asked for approval of another solar contract, with First Solar, for a 20- year PPA that begins at a price of $38.70 per MWh in the first year, but escalates at 3% per year thereafter. The levelized price for this second contract is higher than the levelized $46 per MWh for the Sunpower PPA.

408

Lake City).[20](#_bookmark19) PacifiCorp has stated publicly that the recent solar PPAs which it

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has executed have an average price of $53 per MWh, which is consistent with this range.[21](#_bookmark20) All of the indicative prices that the utility has quoted to the solar QFs

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in its pricing queue are well below this price range. The highest indicative price is

412

$49.54 per MWh. In fact, only 6 out of 55 indicative prices are above the $46 per

413

MWh price for the SunPower contract, a price that is unlikely to be viable in Utah

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415

due to its lower solar insolation. 34 out of the 55 indicative prices are below $40 per MWh.[22](#_bookmark21) The Lawrence Berkeley National Lab (LBNL) tracks utility-scale

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solar PPA prices; its annual *Tracking the Sun* reports are the most authoritative source for such prices.[23](#_bookmark22) LBNL earlier this year discussed the prospects for

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utility-scale solar prices below $50 per MWh, and concluded that they are

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possible in the states in the Southwest U.S. with the most favorable solar resources and the most supportive state policies.[24](#_bookmark23) As a result, it is unlikely that

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any of the solar QF projects in Utah in RMP’s pricing queue will be able to be

422

developed successfully. This conclusion is reinforced by the facts that (1) the

20 Based on $46 per MWh adjusted for 25% lower annual output in Utah compared to southern Nevada. The comparison of the solar resources in Utah versus southern Nevada used the National Renewable Energy Laboratory’s PVWATTS calculator to assess solar output in Utah in Salt Lake City, Delta, and Cedar City, Utah, compared to Las Vegas, for a single-axis tracking project that uses the high-efficiency solar cells that Sunpower manufactures.

21 Docket 14-035-114, *Technical Conference Overview of How Solar is Valued for*

*Avoided Costs* (May 12, 2015), p. 15.

22 Rocky Mountain confidential response to Sierra Club Data Request 2.3.

23 For example, see Bolinger, Mark and Weaver, Samantha, *Utility-scale Solar 2013: an*

*Empirical Estimate of Project Cost, Performance, and Pricing Trends in the U.S.* (LBNL, September 2014); hereafter “LBNL Solar Cost Report.”.

24 Bolinger, Mark; Weaver, Samantha; and Zuboy, Jarrett*, Is $50/MWh Solar for Real?*

*Falling Project Prices and Rising Capacity Factors Drive Utility-Scale PV Toward Economic Competitiveness* (LBNL, May 2015), at pp. 1, 4, and 14; hereafter, *“$50 per MWh Solar Study.”*

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424

expiration of the 30% federal ITC at the end of 2016 could add $15 to $20 per MWh (+20% to +25%) to solar contract prices[25](#_bookmark24) and (2) time is running short for

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these projects to be developed with an on-line date before the end of 2016 to

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qualify for the higher ITC. Utility applications such as this one are creating great

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regulatory uncertainty and thus are helping to “run out the clock” for the solar

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projects in the PacifiCorp pricing queue.

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In addition, even if a project can secure a 20-year PPA from RMP, it may

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not be successfully developed, for a variety of reasons that can include failure to

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gain or maintain site control, local or state permitting difficulties, and an inability

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to secure financing. RMP concedes in discovery that, since 2007, only 75% of QF projects that have executed contracts have been successfully developed[26](#_bookmark25)

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435

and that, among its recently-signed QF PPAs, one 80 MW solar PPA has already terminated.[27](#_bookmark26)

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It is a matter of basic free-market economics that, as prices fall, fewer

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projects will be built. In my judgment, the Commission-approved avoided cost

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method appears to be working as intended. As more solar capacity has been

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added, the avoided cost price has fallen based on RMP’s capacity position and

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future need. It is simply not true that the Commission’s avoided cost methodology

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fails to consider the future need for new capacity – as the need for capacity is

25 Based on the *2012 WECC Generation Costing Tool*, developed by Energy & Environmental Economics for the WECC; available at <https://ethree.com/public_projects/renewable_energy_costing_tool.php>. I assume a

$2,000 per kW utility-scale solar PV capital cost in 2017.

26 Rocky Mountain response to Sierra Club Data Request 1.4, included in Exhibit SC-2.

Data from Idaho indicates that the success rate for QFs with executed contracts in that state may be even lower.

27 Rocky Mountain response to Sierra Club Data Request 2.6, included in Exhibit SC-2.

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pushed further out into the future, the avoided cost price drops. At this point,

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based on the pricing evidence discussed above, it is unlikely that there will be

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further development of solar QFs in Utah. If by some chance additional solar can

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be developed at the new, lower prices that reflect the utility’s current need, then

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Utah’s consumers will benefit from adding new renewable generation at even

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lower costs, at prices better than solar projects anywhere else in the U.S. The

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Commission should continue to allow the market for renewable generation to

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function in Utah, rather than inserting the hand of government regulation to

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change a critical element of that market. I share the perspective of Idaho

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Commission’s staff, which that commission cited in its Order 32697:

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"[t]he proper mechanism for accounting for utility need [in QF pricing] is not to relieve utilities of their obligation to purchase, but instead to establish prices for capacity and energy that properly recognize the utilities’ need, or lack of need, for capacity and energy.”[28](#_bookmark27)

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# Q: Is there a third reason why the Company’s request should be

458

# rejected?

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A: Yes. As I will discuss in detail in the next section, there are many

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benefits of this new renewable generation that are not included in the

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avoided cost price, and that make QF generation a good deal for Utah

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ratepayers. The Commission should reject the Company’s proposal to turn

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its back on these benefits by reducing the term of these PURPA contracts,

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a step that essentially would relieve the utility from its PURPA obligations.

28 Order 32697 at p. 19, citing Tr. at 1090.

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1. RATEPAYER BENEFITS FROM FIXED-PRICE PURPA GENERATION

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# Q: RMP alleges that the continued availability of long-term contracts will inflate the power supply costs borne by its customers.[29](#_bookmark28) Do you

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# agree?

471

A: No. As I will explain below, RMP’s customers will realize significant

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additional net benefits from the utility’s purchase of renewable generation under

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PURPA, benefits that are not included in the avoided cost price. These include:

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1. REC sales revenues, or avoided costs for reducing carbon emissions
2. Hedging benefits
3. Market price mitigation benefits
4. Capacity optionality
5. Local economic benefits

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Generally, it is important to remember that the prices in these contracts

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are set based on the best available estimate of the utility’s avoided costs, that is,

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the costs which the utility would incur if it did not buy from the QF, but instead

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generated the power itself or purchased it from another source. Assuming that

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these estimates are as accurate as possible (see discussion below), then by

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definition these contracts will not have an adverse impact on RMP’s customers,

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because the utility’s costs will be no different than if it had not purchased this

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generation. Estimates of how additional solar or wind contracts would increase

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the Company’s PURPA expenses are irrelevant assuming that the proposed

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contracts are priced at the utility’s avoided costs, because the increased PURPA

29 Application, at p. 21, also, generally, pp. 20-25.

490

expenses will be offset by corresponding reductions in RMP’s costs for the other

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resources that the new PURPA generation will replace. Customers will be at

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least indifferent to the purchase of the PURPA generation, which is the basic

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tenet of PURPA, and are likely to be better off, as a result of the additional

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benefits discussed below.

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# Q: Please respond to RMP’s assertion that this additional PURPA generation will adversely impact customers.”[30](#_bookmark29)

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A: RMP argues that customers may be harmed if avoided costs turn out to be

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lower than forecasted. In discovery, when asked for the impact of these PURPA

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contracts on future retail electric rates, the utility reiterated testimony asserting

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that there may be adverse ratepayer impacts if the Company’s actual avoided costs over the next 20 years are 10% lower than now forecasted.[31](#_bookmark30) Of course,

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the Company also concedes that ratepayers will benefit by a comparable amount

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if the Company’s actual avoided costs over the next 20 years are 10% higher than now forecasted.[32](#_bookmark31) Presumably, there is a roughly equal chance of each

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outcome, and the expected outcome is exactly equal to the forecasted avoided cost on which QF prices are based.[33](#_bookmark32) Mr. Clements’ concern is that these fixed-

30 Application, at pp. 23-25.

31 Rocky Mountain Response to Sierra Club Data Request 2.14, included in Exhibit SC- 2.

32 *Ibid*.

33 This outcome is completely consistent with PURPA. As implemented by the FERC,

PURPA only requires that QF PPA prices reflect the utility’s avoided costs on a forecast basis; ratepayer indifference does not require that QF PPA prices must always equal avoided costs in every hour of every year on an actual basis. 18 CFR §292.304(d)(2) of the FERC’s rules states that a QF has the option to provide energy or capacity on an

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price contracts amount to “speculative trading,”[34](#_bookmark33) placing ratepayers in a position

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where they win if future energy market prices are higher than expected, and lose if they are lower than anticipated.[35](#_bookmark34) Mr. Clements’ entire assertion that

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ratepayers will be harmed by these contracts thus boils down to his own

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speculative bet that future avoided cost will be 10% lower than forecasted today

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– speculation that departs from the utility’s own best forecast on which its

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avoided costs are based.

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The PURPA contract costs for the solar and wind contracts would be fixed

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for the 20-year contract term, while the variable costs of coal, gas, and other

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purchased power will increase significantly over the next 20 years. When costs

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are compared on an apples-to-apples basis and measured over the full expected

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life of these contracts, the PURPA generation is no more expensive than the

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marginal or avoided cost of the generation that it will displace, as required by the

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Commission’s method of setting avoided cost prices. In fact, for the reasons

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discussed below, the solar contracts will offer other benefits that are not included

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in avoided cost prices and that will result in lower power supply costs for RMP’s

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customers.

“as-available” basis, or pursuant to a “legally enforceable obligation for the delivery of energy or capacity over a specified term.” If the second option is selected, Section 292.304(d)(2) then states that the QF has the option to receive avoided cost rates calculated at the time of delivery or at the time the obligation is incurred. In other words, the second option allows avoided cost rates that are forecasted at the time the contract (the “legally enforceable obligation”) is signed.

34 Clements testimony, at p. 22.

1. As I will discuss further below, utilities frequently make other long-term investments –

in generating plants, fuel or pipeline contracts, and transmission lines, for example – that place ratepayers in exactly the same situation; curiously, if those investments are in their rate base, they do not amount to “speculative trading.”

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526

# REC revenues / avoided carbon mitigation costs

**Q: Are there other benefits that RMP’s customers will realize from**

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# PURPA generation?

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A: Yes. RMP can sell the renewable energy credits (RECs) associated with

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the renewable resources that it purchases, and the revenues from these sales

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are a benefit for ratepayers. PacifiCorp projects that the group of recently-

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contracted renewable QFs will provide its utilities with about 1,000,000 MWhs per

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year of RECs systemwide and 790,000 MWhs per year of RECs from the Utah QFs.[36](#_bookmark35)

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# Q: Does PacifiCorp receive significant revenue from these REC sales

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# that benefit its ratepayers?

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A: Yes. These revenues for 2010-2014 are shown in the following table, as

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539

540

well as the average REC price received:

**Table 1:** *RMP REC Sales*

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
|  | **2010** | **2011** | **2012** | **2013** | **2014** |
| **REC Sales***(GWh)* | 3,181 | 2,282 | 4,414 | 1,780 | 793 |
| **REC Sales***($ millions)* | $101.1 | $72.8 | $81.3 | $7.60 | $4.41 |
| **REC Price***($/MWh)* | $31.79 | $31.91 | $18.41 | $4.27 | $5.56 |

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542

I expect that the purchasers of these RECs use them to meet RPS compliance

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obligations in neighboring states in the West. As shown in the table, REC prices

1. Rocky Mountain Response to Sierra Club Data Requests 1.3 and 2.18, included in Exhibit SC-2.

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can fluctuate significantly based on the demand for RECs, the supply of RECs on

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offer, and the compliance status of utilities in the various western states with

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active RPS procurement programs.

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It is my understanding that a portion of the revenues from these REC

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sales is returned to consumers in Utah. Based on this track record, and assuming (1) a long-term price of $10 per MWh for RECs, [37](#_bookmark36) (2) RMP receives 32% of the RECs from these projects,[38](#_bookmark37) and (3) a solar capacity factor of 28%,[39](#_bookmark38)

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an additional 500 MW of solar contracts could add $3.9 million per year in

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additional REC revenues.

554

# Q: Will RMP benefit if it retains the RECs associated with this

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# generation?

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A: Yes. If the RECs are retained and retired, then RMP can claim a

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corresponding share of the carbon emission reductions associated with this

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power. Assuming that 500 MW of potential solar contracts displace gas-fired

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generation at a heat rate of 8.0 MMBtu per MWh, and using the carbon emission

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costs that PacifiCorp assumed in its 2015 IRP for measures incremental to the Clean Power Plan ($22.39 per ton in 2020, escalating at 1.9% per year),[40](#_bookmark39) the

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value of these reductions in carbon emissions from 500 MW of new solar QFs is

37 This is greater than the recent short-term price of about $5 per MWh, and assumes that over the next several decades the West will see periodically stronger REC markets (such as experienced in 2010-2011) as states increase their RPS goals.

38 Based on the amount of RECs supplied to PacifiCorp from the 1,145 of new solar and

wind QF contracts with on-line dates of 2014 or thereafter. See Rocky Mountain Response to Sierra Club Data Requests 2.18, included in Exhibit SC-2.

39 See Rocky Mountain Response to Sierra Club Data Request 2.18.

40 2015 IRP, at pp. 146-147 (Figure 7.6).

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about $3.3 million per year over the life of these resources, or about $2.80 per

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MWh. These benefits can be considered a proxy for the future compliance costs

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that the utility may avoid by increasing its purchases of renewable generation.

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# Hedging benefits

**Q: RMP argues that it is too risky for consumers to commit to long-term**

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# fixed-price contracts. Do you agree?

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A: No. With any fixed-price power purchase contract – and with any

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significant capital investment by the utility in generation or transmission – there is

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always a risk that the alternatives will prove to be less expensive over the long-

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term. This is a risk that consumers bear with PURPA contracts, with other

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purchases in wholesale markets, and with the alternative of utility-owned fossil-

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fuel plants whose capital costs are largely fixed once they are approved for cost

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recovery through rate base and whose fuel costs are subject to significant market

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risk. RMP complains that the prices or terms of QF contracts cannot be modified

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once they are signed, yet it is also difficult to modify the costs for utility-owned

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generation included in the rate base once they have been authorized. And

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ratepayers become exposed to the market risk associated with the fuel costs for

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the utility-owned units.

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Utility-owned generation, and in particular coal units, also face the risk that

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long-term capital costs for rate-based units could increase over time because

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additional capital expenditures may be necessary to continue to operate the units

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in compliance with more protective laws and regulations. Such expenses would

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either increase the overall costs of the utility-owned power plant, or force the

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utility to deal with stranded assets. Both scenarios could increase costs to

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customers in the long-term, which would not happen for a fixed-price QF

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contract.

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If it is too uncertain, too risky, and “speculative trading” to forecast avoided

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cost prices for 20 years, then by the same argument it would also be too risky to

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evaluate the merits of the alternatives to QF power (such as a new utility-owned

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resource or retrofitting an existing fossil fuel plant with expensive pollution

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controls), or even to make decisions based on the long-term projections in an

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IRP.

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The North Carolina commission recognized this in its recent avoided cost

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order, concluding that the uncertainties in future energy markets will impact

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ratepayers regardless of whether the utility contracts with QFs at avoided cost or

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builds its own resources:

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Failure to calculate accurately a utility’s avoided cost means ratepayers will pay for the additional energy and capacity whether the utility builds the plant and places it in rate base or the utility pays QFs avoided cost rates. The Commission concludes that establishing avoided cost rates based upon the best information available at the time and making such rates available in long-term fixed contracts, as required by Section 201 of PURPA should leave the utilities’ ratepayers financially indifferent between purchases of QF power versus the construction and rate basing of utility-built resources.[41](#_bookmark40)

41 North Carolina Avoided Cost Order, at p. 21.

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# Q: Do fixed-price contracts for renewable generation provide a benefit

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# to consumers as a hedge against future uncertainty and volatility in energy

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# and fossil fuel markets?

613

A: Yes. The alternative to the PURPA contracts is reliance on marginal utility

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fossil generation (mostly natural gas-fired) and/or market purchases, whose

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prices also are influenced heavily by gas prices. The value for ratepayers of

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hedging this exposure is simple: fixed-price generation protects against periodic

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spikes in natural gas prices. Such spikes have occurred regularly over the last

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several decades, as shown in the plot of historical benchmark Henry Hub gas prices in **Figure 2** below.[42](#_bookmark41) Hedging against these extreme events can be very

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beneficial for ratepayers.

42 Source for Figure 2: Chicago Mercantile Exchange data.

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Fixed prices also hedge against market dislocations or generation scarcity such

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as was experienced throughout the West during the California energy crisis of

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2000-2001 or as is occurring today with the extreme drought in California and

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long-term, drier-than-normal conditions elsewhere in the West. In 2014, the

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rapidly increasing output of solar projects in California made up for 83% of the reduction in hydroelectric output in the state due to the multi-year drought.[43](#_bookmark42)

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Obviously, there is a risk that consumers may not benefit if future prices turn out

43 Based on Energy Information Administration data for 2014, as reported in Stephen Lacey, *As California Loses Hydro Resources to Drought, Large-Scale Solar Fills in the Gap: New solar generation made up for four-fifths of California’s lost hydro production in 2014* (Greentech Media, March 31, 2015). Available at [http://www.greentechmedia.com/articles/read/solar-becomes-the-second-biggest-](http://www.greentechmedia.com/articles/read/solar-becomes-the-second-biggest-renewable-energy-provider-in-california)  [renewable-energy-provider-in-california](http://www.greentechmedia.com/articles/read/solar-becomes-the-second-biggest-renewable-energy-provider-in-california).

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to be lower than anticipated, but, if that happens, consumers will enjoy the low

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prices for the portion of their needs that is not hedged. Despite this risk, hedging

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in a commonly accepted practice in utility operations and regulation.

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Many utilities, including those in Utah, conduct risk management programs

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that include hedging that uses a variety of forward market instruments and that is

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designed primarily to reduce the near-term volatility of their short-term fuel and

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purchased power expenses. Generally, these programs focus on reducing

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volatility only in the next 1-3 years, as the forward markets are most liquid in the

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near-term and there are substantial transaction costs associated with long-term

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hedges in financial markets, if such hedges are even available. However, utilities

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regularly engage in long-term hedging through their resource portfolios, and

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companies such as PacifiCorp are careful to evaluate their overall risk position as

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including both their short- and long-term positions in both natural gas and power.

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Significantly, PacifiCorp’s discussion of its hedging program in its 2015 IRP

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emphasizes how its long position in the power market can function as a hedge

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against its short position in natural gas, and concludes that “[t]his has the effect

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of reducing the amount of natural gas hedging that the Company would otherwise pursue.”[44](#_bookmark43) This is exactly the hedge represented by the fixed-price QF

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contracts at issue in this case. In addition, other observers have noted that long-

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term, fixed-price contracts for renewable generation provide utilities with a means

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not available in the financial markets to hedge their long-term exposure to gas

44 2015 IRP, at pp. 246-247.

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and power markets, and thus could replace a portion of their current budgets for risk management.[45](#_bookmark44)

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The economic literature generally finds that the fixed-price, zero-fuel-cost

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nature of renewable generation provides a positive value as a hedge against

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future increases in fossil fuel prices. For example, in a recent study LBNL

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compared fixed-price, long-term wind contracts to the range of expected prices

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657

for gas-fired generation, based on the range of recent Energy Information Administration (EIA) gas cost forecasts.[46](#_bookmark45) LBNL concluded that current wind PPA

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prices in the range of $50 per MWh offer significant benefit as a hedge against

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the expected range of future fossil fuel prices, even in today’s low-price

660

environment for natural gas as a result of the shale gas revolution. Here is the

661

key figure from the LBNL study:

45 Lisa Huber, *Utility-scale Wind and Natural Gas Volatility: Unlocking the Hedge Value of Wind for Utilities and Their Customers* (Rocky Mountain Institute [RMI], July 2012), at pg. 15, available at [http://www.rmi.org/Knowledge-Center/Library/2012-](http://www.rmi.org/Knowledge-Center/Library/2012-07_WindNaturalGasVolatility)  [07\_WindNaturalGasVolatility.](http://www.rmi.org/Knowledge-Center/Library/2012-07_WindNaturalGasVolatility)

46 Bolinger, Mark, *Revisiting the Long-term Hedge Value of Wind Power in an Era of*

*Low Natural Gas Prices* (LBNL-6103E, March 2013), available at [http://emp.lbl.gov/sites/all/files/lbnl-6103e.pdf.](http://emp.lbl.gov/sites/all/files/lbnl-6103e.pdf)

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663

A number of studies have quantified these hedging benefits. In the West, Public

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Service of Colorado has estimated that the long-term (20-year) hedging benefits of distributed solar resources on its system are $6.60 per MWh.[47](#_bookmark46)

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# Q: Mr. Clements’ testimony discusses at length the company’s policies

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# with respect to hedging in short-term commodity markets (which generally

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# limit hedges to no more than 36 months), and suggests that executing a long-term QF PPA at a fixed price would be contrary to those policies.[48](#_bookmark47) Do

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# you agree?

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A: No. The problem with this discussion is that QFs are not short-term energy

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commodities such as a 30-day spot gas supply, but are long-term, steel-in-the-

47 Xcel Energy Services, *Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System: Study Report in Response to Colorado Public Utilities Commission Decision No. C09-1223* (May 2013), at pp. 6 and 43, and Table 1. This study used the cost of options contracts in the gas futures market to calculate the hedging benefit. Similar methods have been used in many other solar valuation studies in other regions of the U.S.

48 Clements testimony, at pp. 15-23.

673

ground power plants with 20+ year lives. There is no liquid market for QF projects

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in the same way that there are markets for spot gas at Opal, Wyoming or for day-

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ahead on-peak power at Mid-C. If the utility subjected the generation resource

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acquisitions that it owns to its own short-term hedging policies, it could never

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receive more than 36 months of assured rate recovery for the non-fuel capital

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and operating costs of a power plant. I doubt that the Company would build a

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power plant under those conditions, nor can a QF developer.

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Mr. Clements complains that, if the Company were to consider a longer-

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term hedge such as a fixed-price QF contract, the utility generally would require

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more detailed review and more extensive planning than it is allowed to devote to

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a must-purchase QF contract. In addition, the utility would procure the long-term resource through a more competitive procurement process.[49](#_bookmark48) Fundamentally, this

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is a complaint about the limitations which the PURPA must-purchase obligation

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imposes on the state’s procurement process for long-term utility resources.

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Fortunately, the EPAct of 2005 and the FERC have already solved this problem,

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by providing states with a means to remove the PURPA must-purchase

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obligation if a state can show that QF resources have a comparable long-term

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market for their energy and capacity. As noted above, other states that have

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gone through this process have implemented exactly the same long-term

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planning and procurement processes for renewable QF resources that Mr.

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Clements wishes he could use for QF procurement in Utah. What states cannot

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do under the PURPA paradigm is to treat QFs as short-term resources,

49 *Ibid*., at pp. 17-20.

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frustrating QF development and the intent of PURPA by limiting them to short-

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term power sales, as RMP has proposed here.

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# Q: Do you agree with Mr. Clements that because QF projects do not

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# undergo the “same extensive IRP process” as utility-owned resources,

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# they should be limited in the contract term which they receive, in order to limit ratepayer exposure to pricing risks?[50](#_bookmark49)

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A: No. The QF procurement process differs from that for utility-owned

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resources, as a result of the PURPA must-purchase obligation, but in my opinion

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the QF process also represents a thorough screening of potential QF resources.

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First, the Commission approves an avoided cost methodology developed through

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a fully litigated Commission docket with multiple parties. Second, the utility’s

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comprehensive IRP process establishes a future resource plan, including the

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timing of the utility’s future need for generation, and models the utility’s avoided

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energy and capacity costs associated with that plan. This extensive process,

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combining both the IRP and the Commission’s approved avoided cost

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methodology, establishes the level and timing of both the capacity and energy

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payments unique to each proposed QF, and has regular updates to ensure

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accurate information as time moves forward. Importantly, Utah’s method for

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calculating avoided costs also relies on the utilities’ IRPs and thus provides the

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same assumptions, uses the same tools, and is subject to the same robust

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scrutiny as utility proposals to build owned resources. Once a QF and utility

50 Clements testimony, at p. 19.

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negotiate a contract, the Commission must approve the contract to ensure

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adherence to Utah’s adopted rules and practices. Finally, as more QF generation

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is added, avoided costs decline, and ultimately the avoided cost price will fall to a

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level that no longer allows successful QF development. As discussed above, we

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may be at that point in Utah today.

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# Q: Are QF contracts less risky for ratepayers in certain ways than

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# utility-owned resources?

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A: Yes. QF contracts include performance guarantees by the QF that are

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more stringent than those which apply to a utility-owned plant. QFs must actually

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deliver energy within the performance bounds contained in the contracts to

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receive any payments. They are not paid if the QF project is never built or fails to

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operate correctly. They are not paid for over-delivery and they are penalized for

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under-delivery. The only element of the contractual payment which is guaranteed

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is the rate. This is substantially riskier for the QF project than an investment in

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generation assets is for the utility. Once a utility generation asset is approved for

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rate recovery through the utility’s rate base, the utility will recover its costs,

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including the necessary fuel costs, and earn a return, even if the plant is out of

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service or does not perform with the efficiency originally advertised. The only

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circumstance in which this assured return will be reduced is the infrequent event

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that the Commission finds, typically after a lengthy regulatory process, that the

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utility’s operation of the plant was imprudent or unreasonable. No such finding is

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required to deny payment to a QF project: if the QF fails to deliver per the

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contract, it is not paid. Ratepayers benefit from the QF’s assumption of this

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greater level of operating risk, compared to utility-owned generation.

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# Market Price Mitigation

**Q: Will an increasing penetration of new renewable generation in**

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# Utah and the West have an impact on energy market prices?

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A: Yes. This new solar generation will increase the electricity supplies

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available to RMP and PacifiCorp. Because this generation is must-take (and has

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zero variable costs), it will displace the most expensive fossil-fired or market

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resources that the Company would otherwise have generated or purchased. The

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addition of this local generation will reduce the demand which the utility places on

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the regional markets for electricity and natural gas. With this reduction in

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demand, there is a corresponding reduction in the price in these markets, which benefits the Company when it does buy power or natural gas in these markets.[51](#_bookmark50)

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As discussed in PacifiCorp’s IRP, the Company expects to have a short position in these markets for many years into the future.[52](#_bookmark51) This “market price mitigation”

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benefit of renewable generation is widely acknowledged, and has become highly

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visible in markets that now have high penetrations of wind and solar resources.

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The magnitude of these benefits will depend on the overall amount of renewables

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on the western grid.

51 This same effect is visible in the Company’s indicative prices for QF generation. As more such generation is added to the system, the marginal or avoided cost for the utility declines, as a more efficient unit becomes the marginal supply source.

52 The 2015 IRP, at 10 and Action Item 2a, shows that the Company will rely on unspecified market purchases (“front office transactions”) to balance its loads and

resources for many years to come.

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# Q: Are you aware of any modeling of this benefit in the West?

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A: Yes. The National Renewable Energy Laboratory (NREL) and GE

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Consulting have undertaken the Western Wind and Solar Integration Study

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(WWSIS), a major, multi-phase modeling effort to analyze much higher penetrations of wind and solar resources in the western U.S.[53](#_bookmark52) Although this

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work focused on the West Connect area (basically, Arizona, Colorado, New

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Mexico, Nevada, and Wyoming), the modeling has included the entire WECC

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grid in the U.S., including Utah. For example, the WWSIS study of high

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penetrations of solar (25% penetration in West Connect) also included 15% solar

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penetration in nearby states, including 2,500 MW of solar in Utah. This modeling

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included analysis of the impact of increasing solar penetration on market prices

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in the West; the results for spot prices in Arizona are shown in the figure below.

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Generally, the high penetration solar cases (15% to 25% penetration) result in

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10% to 20% reductions in spot market prices. Note that the largest reductions in

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market prices from a 5% increase in penetration occurs at the low penetrations of

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solar, which is where the West is today. Only in California is on-line solar

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penetration approaching even 5% today.

53 The high penetration solar results from the WWSIS are reported in *Impact of High Solar Penetration in the Western Interconnection* (NREL and GE Consulting, December 2010), at p. 8 and Figure 19. This report, as well as all reports from the WWSIS, are available on the NREL website at <http://www.nrel.gov/electricity/transmission/western_wind.html>.

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The same market mitigation benefits exist on the natural gas side. Renewable

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generation reduces marginal gas-fired generation, thus lowering the demand for

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natural gas. A study by LBNL has estimated that the gas-related market

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mitigation benefits of renewable energy range from $7.50 to $20 per MWh of renewable output.[54](#_bookmark53)

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As context for how these market price reductions might benefit Utah

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consumers, PacifiCorp expects that short-term market purchases (so-called

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787

“front office transactions”) will continue to play a significant role in balancing its resource portfolio in coming years.[55](#_bookmark54)

54 *See* Wiser, Ryan; Bolinger, Mark; and St. Clair, Matt, “Easing the Natural Gas Crisis: Reducing Natural Gas Prices through Increased Deployment of Renewable Energy and Energy Efficiency” (January 2005), at ix, available at <http://eetd.lbl.gov/sites/all/files/publications/report-lbnl-56756.pdf>.

55 2015 IRP, at p. 10, Action Item 2a.

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# Q: Are the fuel hedging and market price mitigation benefits that you

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# have calculated related?

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A: They are related in that both involve energy market prices for electricity

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and natural gas. The fuel hedging benefit for consumers results from a reduction

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in the volatility of these market prices – in other words, in a reduced risk of

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periodic price spikes in these commodity markets. The market price mitigation

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benefit is from an overall reduction in the levels of these market prices. Thus,

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these benefits are related but do not necessarily overlap.

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# Q: Will some of PacifiCorp’s other potential future resource options

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# also realize such benefits?

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A: Yes. To be fair, any new sources of renewable or low-variable-cost

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generation will produce such benefits.

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# Capacity optionality

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# Q: Will these additional solar resources provide new generating

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# capacity in RMP’s service territory?

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A: Yes. In developing the 2015 IRP PacifiCorp assumes that solar generation will provide annual capacity equal to about 34% of its nameplate capacity.[56](#_bookmark55)

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Thus, each additional 100 MW (AC) of solar resources would add 34 MW of

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capacity. All of this capacity would be internal to RMP’s system, and will not

56 *Ibid.*, at p. 405.

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require additional out-of-state transmission capacity to be deliverable to its

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customers in Utah.

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# Q: Initial results from PacifiCorp’s 2015 IRP show the next need for

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# capacity is not until 2028. This assumes that the 816 MW of approved PURPA contracts are included in the resource stack.[57](#_bookmark56) Is there a potential

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# benefit if additional solar and wind capacity comes on-line before it is

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# expected to be needed under the utility’s current IRP?

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A: Yes. RMP has no immediate need for capacity based on its current IRP,

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and this lack of need is priced into the solar contracts, both those that the utility

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has signed recently and those that it might sign in the near future. This assumed

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lack of need results in lower prices in these contracts. However, events may

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occur that accelerate PacifiCorp’s need for capacity. One possible factor that

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could accelerate PacifiCorp’s need is the orderly retirement of a portion of the

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utility’s coal capacity, which could occur for a variety of reasons, including the

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cost of additional emission controls and/or compliance needs related to the

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federal government’s Clean Power Plan.

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As a result, the possible renewable contracts provide PacifiCorp with an

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essentially free option to replace existing capacity prior to the current date when

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capacity otherwise is expected to be needed. In other words, customers in Utah

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will gain insurance, at no cost, against events which might challenge reliability

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should a new need for capacity arise.

57 *Ibid.*, at pp. 2, 4.

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# Local economic benefits

**Q: Will there be economic benefits for Utah from additional**

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# development of the state’s indigenous resources?

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A: Yes. The construction of each additional 500 MW of solar generation in

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Utah will represent an investment of $1.5 billion in the state, assuming a capital cost of $3,000 per kW.[58](#_bookmark57) Not all of this money will be spent in Utah, of course,

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but there will be significant short-term employment benefits during construction

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as well as permanent employment operating and maintaining these facilities, as

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well as royalties to landowners and property taxes to local communities.

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Significantly, because these facilities will be located in Utah, the economic

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benefits are more likely to accrue locally than if these were out-of-state power

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plants or power purchases from regional markets.

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# A window of opportunity to procure low-cost solar

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# Q: Is today a good time to purchase new solar generation?

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A: Yes. Natural gas prices today are quite low in historical terms, particularly

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for longer-term forward contracts. Figure 2 above also shows several examples

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of the 10-year forward price for natural gas at the Henry Hub in recent years.

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This shows that today’s avoided costs are relatively low. New sources of clean

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energy are becoming competitive with this price. Put simply, if today’s

58 LBNL Solar Cost Report, at pp. 11-14

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independent QF developers can meet or beat this avoided cost, then it will be a

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good deal for ratepayers.

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# Q: Is this a good time to contract for new solar generation, in terms of

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# the price for this renewable generation?

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A: Absolutely. It is critical to recognize that the 30% federal investment tax

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credit (ITC) expires at the end of 2016, after which it will drop to 10%. As a result,

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the levelized cost of solar generation is expected to rise significantly for several

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years beginning in 2017, until cost reductions for this technology can offset the

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loss of this significant incentive. Using a generation cost tool developed for the

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WECC, the drop in the federal ITC could add $15 to $20 per MWh (+20% to

+25%) to solar contract prices after 2017.[59](#_bookmark58) As a result, now is an opportune

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moment to purchase solar generation at contract prices that may not be available for a considerable period after 2016.[60](#_bookmark59) Based on solar PPA prices surveyed by

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LBNL through mid-2014, utility-scale PPA prices in the range of $50 to $60 per

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MWh represent reasonable prices comparable to the solar PPAs being procured elsewhere in the country, as shown in the figure below.[61](#_bookmark60)

59 Based on the *2012 WECC Generation Costing Tool*, developed by Energy & Environmental Economics for the WECC; available at https://ethree.com/public\_projects/renewable\_energy\_costing\_tool.php, assuming a

$2,000 per kW utility-scale solar PV capital cost in 2017.

60 This is what the California utilities concluded in 2013, even though they had largely contracted adequate generation to reach the state’s 33% by 2020 RPS goal. See the

article cited in Footnote 29 above.

61 This is Figure 1 from the LBNL *$50 per MWh Solar Study,* and is based on multiple data sources that LBNL uses to track utility-scale solar PPA prices in the U.S.

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1. SYSTEM RELIABILITY

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# Q: Are you concerned that PacifiCorp would have difficulty integrating

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# additional intermittent solar generation into its system?

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A: No. The integration of higher levels of wind and solar resources presents a

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challenge to utilities and grid operators across the U.S., not just in the West. In

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recent years, significant effort and numerous studies have been conducted on

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the operational and system reliability impacts of the increasing penetration of

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variable renewable resources. The WWSIS is the most significant such effort in

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the WECC. As noted above, the WWSIS included a high solar penetration study

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that considered a 25% solar penetration in the West Connect area, and 15%

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penetration in the rest of the WECC (including 2,500 MW of solar in Utah). The

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WWSIS concluded that it will be feasible to operate the WECC grid at these

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levels of solar penetration in the WECC, provided that certain operational

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changes are made. The key findings of the WWSIS include:

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* Increasing the size of the geographic area over which the wind and solar resources are drawn substantially reduces variability.
* Scheduling generation and interchanges subhourly reduces the need for fast reserves.
* Using wind and solar forecasts in utility operations reduces operating costs by up to 14%.
* Existing transmission capacity can be better used. This will reduce new transmission needs.
* Demand response programs can provide flexibility that enables the electric power system to more easily integrate wind and solar—and may be cheaper than alternatives.

Efforts are already underway to implement such changes. Most notably,

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PacifiCorp has joined with the CAISO to create a new energy imbalance market

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(EIM) that is intended, among other benefits, to address the first two findings of

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the WWSIS – balancing wind and solar resources over a larger geographic

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footprint and reducing the costs of integrating such resources by balancing the

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system more efficiently on a sub-hour basis. A white paper from the FERC staff

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explains the benefits of an EIM for renewable integration:

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An EIM could enhance the reliability of the bulk power system as the system moves towards higher levels of variable energy resources. Balancing authorities need reserves that are loaded and able to reduce output, as well as reserves that are unloaded and able to increase output, in order to respond to the variability from variable energy resources. Without an EIM, the variability from variable energy resource output in the Western Interconnection is not diversified across balancing authorities. An EIM could help manage variable energy resources more reliably by pooling variability over a larger area, and redispatching resources to help manage imbalance energy caused by variable energy resources.[62](#_bookmark61)

62 FERC, *Qualitative Assessment of Potential Reliability Benefits from a Western Energy*

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The EIM began operations on November 1, 2014, and achieved $6 million in savings for its participants in just the first two months of operation.[63](#_bookmark62) NV Energy

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and Puget Sound Energy will be joining the EIM in October 2015 and October

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2016, respectively. In essence, the EIM promotes the more granular and efficient

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exchange of power among the participating control areas.

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Although the WWSIS study showed the ability to integrate 15 – 25% solar

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penetration, the rest of the West, except for California, is not close to even a 5%

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level of solar penetration today. Thus, today RMP / PacifiCorp should be able to

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integrate higher levels of solar generation on its system, especially if it can obtain

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greater access to balancing resources in the region through mechanisms such as

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the EIM.

# Q: Does this conclude your direct testimony?

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**A:** Yes, it does.

*Imbalance Market* (February 26, 2013), at p. 17, available at [http://www.caiso.com/Documents/QualitativeAssessment-PotentialReliabilityBenefits-](http://www.caiso.com/Documents/QualitativeAssessment-PotentialReliabilityBenefits-WesternEnergyImbalanceMarket.pdf)  [WesternEnergyImbalanceMarket.pdf](http://www.caiso.com/Documents/QualitativeAssessment-PotentialReliabilityBenefits-WesternEnergyImbalanceMarket.pdf).

63 CAISO, *Benefits for Participating in EIM* (February 11, 2015), Slide 3, available at [http://www.caiso.com/Documents/Presentation-](http://www.caiso.com/Documents/Presentation-PacifiCorp_ISO_EIMBenefitsReportQ4_2014.pdf)

[PacifiCorp\_ISO\_EIMBenefitsReportQ4\_2014.pdf](http://www.caiso.com/Documents/Presentation-PacifiCorp_ISO_EIMBenefitsReportQ4_2014.pdf).