BEFORE THE PUBLIC UTILITY COMMISSION OF THE STATE OF OREGON

UM 1734

In the Matter of	**)**
	)
PACIFICORP d/b/a PACIFICORP	**)**
	)
Application to Reduce the Qualifying Facility Contract Term and Lower the Qualifying Facility Standard Contract Eligibility Cap	**))**

The Sierra Club

Direct Testimony of Patrick G. McGuire

October 15, 2015

TABLE OF CONTENTS

EXECUTIVE SUMMARY

PacifiCorp d/b/a Pacific Power ("PacifiCorp" or "the Company") 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 587 MW of additional contracts with renewable QF projects, mostly solar, which presently have been proposed to be developed in its Oregon 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 PacifiCorp's Application. First, there is no crisis of QF's coming on to PacifiCorp's system in Oregon that warrants the draconian response proposed by the Company. Current Schedule 37 prices, as well as the indicative prices that PacifiCorp has provided to larger renewable QFs under Schedule 38, show that PacifiCorp's avoided costs for new renewable generation are dropping, in part due to new renewables replacing progressively less expensive marginal fossil generation. These prices, when compared on an apples-to-apples basis with the lowest public PPA prices for solar in the western U.S., show that few of the solar QFs located in Oregon that are in PacifiCorp's pricing queue are likely to be successfully developed at current Schedule 37 or 38 prices. Furthermore, even among the projects that have secured a contract with 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 Oregon, and thus no need for the Commission to shorten the QF contract term to a length that will no longer encourage the development of solar and wind QFs in Oregon. To the contrary, PURPA is functioning as intended to allow renewable energy developers to compete with the utility if they are able to provide low cost power to customers.

Second, PacifiCorp's proposal to shorten contract terms to three years violates PURPA. 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. Shortening those contracts therefore contradicts the legal requirements of PURPA to encourage the development of qualifying renewable generation that can be developed at the utility's avoided costs. If PacifiCorp 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 Commission and the state of Oregon to assume greater control over utility procurement of renewable generation.

Third, 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. These prices are the result of Oregon's comprehensive Integrated Resource Planning process, and also represent the avoided costs against which other resource options, including utility-owned resources, are evaluated. As a result, PacifiCorp'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 PacifiCorp'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 PacifiCorp to purchase low-cost solar generation before the 30% federal investment tax credit expires at the end of 2016.

- **Renewable value.** PacifiCorp will gain additional value for its ratepayers from the environmental benefits of this new renewable generation. These benefits can be valued in several ways. First, one can consider the potential revenues from the sale of the renewable energy credits (RECs) that the utility may acquire along with this power. Second, one can calculate the reduced costs to comply with future regulations requiring higher 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 generally is 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 millions of dollars in clean energy infrastructure in the state of Oregon over the next several years. If these projects are not built in Oregon, they could be developed in one of the surrounding states that also are rich in renewable resources.

This testimony quantifies many 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 Oregon.

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 indicating that a much higher penetration of solar generation is feasible in the Western Electricity Coordinating Council (WECC) than what would result from these QF 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.

I. INTRODUCTION

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

A: My name is Patrick G. McGuire. I am policy advisor at the consulting firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 213A, Berkeley, California 94710.

Q: Please describe your experience and qualifications.

A: I have over 25 years of experience in utility analysis, resource planning, and rate design. I have extensive experience with the Renewable Portfolio Standard (RPS) programs in several states, including the impacts of such programs on retail rates and the valuation of Renewable Energy Credits (RECs). I also have worked on a wide variety of issues concerning power purchase agreements between utilities and qualifying facilities under the Public Utilities Regulatory Policies Act of 1978 (PURPA). My recent work on net energy metering has included detailed cost/benefit analyses of renewable distributed generation resources in a number of states across the U.S., including Arizona, California, Colorado, and North Carolina. I have testified on cost allocation and PURPA issues before the state commissions in California and Vermont. My resume is attached to this testimony as Exhibit SC-1.

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

A: I am appearing on behalf of the Sierra Club.

The Sierra Club is a national, non-profit environmental and conservation organization dedicated to the protection of public health and the environment. Sierra Club is participating in this matter on behalf of itself and the approximately 17,000 Sierra Club members who live and purchase utility services in Oregon. Sierra Club's Oregon members have a direct and substantial interest in this proceeding as a result of its potential impact on additional solar deployment in Oregon and on the environmental, health and economic benefits that would result from the addition of this renewable generation to PacifiCorp's electric system in Oregon.

Q: Have you previously testified or appeared as a witness before the Public Utility Commission of Oregon?

A: No.

Q: Do you have any exhibits?

A: Yes. Exhibit SC-1 is my resume. Exhibit SC-2 are certain discovery responses from PacifiCorp. Exhibit SC-3 is a fact sheet from PacifiCorp about the new Energy Imbalance Market involving PacifiCorp, the California Independent System Operator (CAISO), Puget Sound Electric, and NV Energy.

II. BACKGROUND ON PURPA

Q: PacifiCorp's Application generally describes the requirements of PURPA. Do you have anything to add to this background?

A: Yes. As a consultant with over 25 years of experience in PURPA-related issues, I offer the following economic perspective. Congress enacted PURPA to encourage a new, free market for the independent development of generation from resources that would reduce our nation's dependence on fossil fuels, with the goal of increasing the energy security and independence of the United States. PURPA required public utilities, who enjoyed a state-sponsored monopoly in the generation market, to purchase power from cogeneration and small renewable power producers, collectively called "qualifying facilities" or QFs, at prices that could not exceed the utilities' "avoided cost." In the words of the statute, avoided costs are "the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source."[1] PURPA's must-take requirement at an avoided cost price was intended to offset the monopsony power[2] of the utility as the sole buyer of generation in its service territory. Congress limited purchase

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

price to the utility's avoided cost in order to achieve a balance between the interests of ratepayers and PURPA generators, so that the price would be both "just and reasonable to the electric consumers of the electric utility and in the public interest" and "not discriminate against qualifying cogenerators or qualifying small power producers" in comparison to the utility's other supply options. The FERC and the courts have found that a price set at 100% of the utility's avoided cost satisfies this dual standard and the intent of PURPA to encourage QF development.[3] In essence, the economic design of PURPA was to simulate the outcome of a free and open market that would encourage QF development, if QFs could offer generation at a competitive cost equal to or less than the incremental cost to the utility of procuring power from other sources. PURPA generation purchased at the avoided cost price would be reasonable for the consumer because it would be no more expensive than if the monopoly utility had generated the power itself or purchased it from another source.

Q: PURPA was enacted almost four decades ago. Have Congress and the FERC enacted significant changes to PURPA since then?

A: Yes. PURPA was the key first step in the development of independent power generation in the U.S. The success of this new industry in many states under the PURPA framework enabled the creation, in the 1990s and early 2000s, of viable and less-regulated markets for electric generation in many regions of the U.S. Over time, these markets have expanded to include, in some states, competition in generation at both retail and wholesale levels, as well as non-discriminatory access to electric transmission through regional transmission organizations (RTOs) with independent system operators of the transmission grid. In addition, many states have enacted renewable portfolio standard (RPS) programs, based on states' traditional authority over utility procurement, designed to provide long-term markets for the new renewable generation that previously had been developed principally through PURPA. Responding to these developments, Congress enacted the Energy Policy Act of 2005 (EPAct), which implemented a new

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

Section 210(m) of PURPA. This section allowed a utility to petition the FERC for relief from the "must purchase" requirement of PURPA if FERC found that QFs in that utility's territory have access to sufficiently competitive wholesale markets for long-term sales of capacity and electric energy.

Q: Have utilities in other states and regions successfully petitioned the FERC under Section 210(m) of PURPA to end the PURPA must-purchase obligation?

A: Yes. However, this has occurred in states that have opened their generation market to substantial competition at the wholesale level. For example, when the major California investor-owned utilities (IOUs) successfully petitioned the FERC for relief from the PURPA must-purchase obligation for QFs larger than 20 MW, they were able to show that California had taken the following steps to provide viable long-term wholesale markets for QF generation:

- 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]

---

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

The fact that the U.S. Congress and the FERC have found that a state must create long-term wholesale markets for energy and capacity from QFs in order to end PURPA's must-purchase obligation indicates clearly that the fundamental purpose of the PURPA program continues to be to provide such a long-term market for QF generation.

Q: It has been asserted that the RTOs in which the PURPA must-purchase obligation has ended do not provide markets for wholesale sales longer than three years.[5] Do you agree with this argument?

A: No. The flaw in this argument is that the key feature necessary to end the PURPA must-purchase obligation is that renewable and cogeneration resources must have access to <u>long-term</u> power purchase agreements. These new long-term markets are based on procurement programs, principally RPS programs, sponsored by the states under their authority over utility procurement, not through the RTOs. Again, the California RPS program noted above is an example of such a state-sponsored RPS program that provides long-term contracting opportunities for renewable QFs in California, and that has allowed the termination of PURPA's mandatory purchase obligation in that state. 29 states have RPS programs, including Oregon.[6]

Q: How has PacifiCorp described its PURPA obligations as they relate to long-term planning?

A: PacifiCorp asserts that it is not allowed to consider need in acquiring PURPA resources, and that it must purchase long-term QF generation that it does not need. The Company complains that QFs are not subject to the comprehensive planning process by which it identifies long-term needs in its biennial Integrated Resource Plan (IRP) process,[7] although I see no reason that the Company could not consider possible QF generation that is likely to be available at avoided cost prices as a resource option in its IRPs, in the same way that it considers other sources of market-priced generation.

---

[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 website data on RPS programs.
[7] Application, at p. 27; Griswold testimony, at pp. 23-25.

Q. How does PacifiCorp propose to address this issue?

A: The Company is essentially asking the Commission to prevent most future PURPA contracts in Oregon, particularly for renewable QFs, by shortening the contract term in a manner that would almost certainly prohibit renewable QF developers from obtaining financing.

Q: Should the Commission reject the Company's proposal to reduce from 20 years to three years the maximum term for prospective PURPA contracts for QF projects?

A: Yes. The proposed reduction in the maximum term for these QF contracts should be rejected, for the reasons presented below.

III. PACIFICORP'S SYSTEM WILL NOT BE OVERWHELMED BY MANDATORY QF PROJECTS

Q: PacifiCorp witness Bruce Griswold raises the specter that its Oregon system could be overwhelmed with an additional 587 MW of unwanted QF generation.[8] Please put the amount of QF capacity in Oregon in perspective.

A: PacifiCorp is not being overwhelmed by QF development in its Oregon service territory. The record shows that the utility has added 71 MW of operational wind, solar, and geothermal QFs since the contract term was raised to 15 years in 2005, an average of less than 10 MW per year. The utility now has an additional 252 MW of wind and solar projects with signed contracts that are not yet on-line. The utility states that the historic "success rate" of QFs with signed contracts being able to bring their projects on-line is 75%, so the utility may add about another 189 MW of QFs, representing about 69 MW of firm capacity.[9] PacifiCorp's peak load obligation for its western system, including its Oregon service territory, is forecasted to be 3,655 MW in 2017 with expected load

[8] Exh. PAC/100 (Griswold testimony), at p. 11, line 3 and Table 2.

[9] PacifiCorp response to Sierra Club DR No. 1.4(a), included in Exhibit SC-2. The firm capacity assumes that wind and solar projects in Oregon contribute firm capacity equal to 14.5% and 39.1% of their nameplate capacity, respectively. See 2015 IRP, at p. 405.

growth of 34 MW per year from 2015 to 2024.[10] Thus, the recent 69 MW of expected firm capacity additions from renewable QFs represent two years of load growth for PacifiCorp's western system, and less than 2% of the utility's peak demand for its eastern system. The utility has received pricing requests from another 587 MW of mostly solar projects in Oregon, but, as we shall discuss below, the current economics for these projects are not favorable.

Q: Will the Commission's current approach to setting avoided cost prices for long-term QF contracts result in unlimited QF development in Oregon?

A: No. The Commission's current pricing mechanism will act on its own accord to limit QF development to what is economic for ratepayers. This is the first reason to reject PacifiCorp's request. The Commission's current method used to set long-term avoided cost prices in Oregon, as adopted in Order 14-058, allows the utility to update its avoided costs at least every year as well as after the Commission acknowledges a new IRP. These updates can include current natural gas forecasts, forward electric market prices, and "any other action or change in an acknowledged IRP update relevant to the calculation of avoided costs."[11] The result of such updates to avoided costs is that the price in solar contracts will decline as fuel cost and load forecasts are revised and as additional QF contracts are added.

The market for QF power in Oregon appears to be working in exactly this way. The most recent update to Schedule 37 prices, in May 2015, showed a decline in the prices applicable to standard offer QFs 10 MW or smaller.[12] Both today's Schedule 37 prices, as well as the indicative prices under Schedule 38 that PacifiCorp has quoted to the larger solar QFs in its pricing queue, indicate that few, if any, of the solar projects in Oregon that are now in the utility's queue can be economically developed.

[10] 2015 IRP, at Table 5.14. Load obligations include reserve requirements.
[11] See Order No. 14-058, at pp. 26.
[12] All of the solar QFs in Oregon with existing contracts have used pricing from Schedule 37 which predates the most recent revision.

Q. Why do you say that projects are unlikely to be developed at current avoided cost pricing?

A. The lowest 20-year solar PPA price in the western U.S. that has been 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.[13] The 20-year levelized price in this contract is $46.00 per MWh. The project is expected on-line by the end of 2016 to qualify for the 30% federal investment tax credit, although this is not certain, as the project obviously needs to obtain financing, secure necessary permits, and complete construction in this time frame. The SunPower project is sited in a special zone for solar projects and is adjacent to major substations, giving it the advantage of a solar resource that will produce about 21% to 32% more annual output than a comparable project in the most favorable locations in eastern and southern Oregon. The SunPower project also has minimal transmission upgrade costs as a result of its location adjacent to major substations. This indicates that the minimum 20-year levelized avoided cost price likely to be needed in Oregon for a possibly-viable utility-scale solar project is in the range of $56 to $61 per MWh.[14] If a project incurs significant transmission upgrade costs, the likely necessary PPA price is above $60 per MWh. Current 15-year levelized Schedule 37 prices for a solar PPA are no higher than the lower end of this range, about $57 to $58 per MWh, and the Schedule 38 indicative prices that the utility has quoted to the larger (above 10 MW) solar QFs in its pricing queue are just $45 per MWh.[15] The Lawrence Berkeley National Lab (LBNL) tracks utility-scale solar PPA prices; its annual *Tracking the Sun* reports are

---

[13] 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.

[14] Based on $46 per MWh adjusted for 21% (Klamath Falls) to 28% (Redmond) to 32% (Baker City) lower annual output in eastern Oregon compared to southern Nevada. The comparison of the solar resources in Oregon versus southern Nevada used the National Renewable Energy Laboratory's PVWATTS calculator to assess solar output in a number of locations in Oregon, compared to Las Vegas, for a single-axis tracking project that uses the high-efficiency solar cells that Sunpower manufactures.

[15] This is true of the indicative prices that PacifiCorp has quoted to its QFs in Idaho and Utah as well as Oregon. *See* PacifiCorp response to Confidential Sierra Club Data Request 1.11.

the most authoritative source for such prices.[16] LBNL earlier this year discussed the prospects for utility-scale solar prices below $50 per MWh, and concluded that they are possible, but only in the states in the Southwest U.S. with the most favorable solar resources and the most supportive state policies.[17]

Based on this analysis, it is likely that the solar QF projects in Oregon in PacifiCorp's pricing queue are, at best, only marginally economic, and that few, if any, will be able to be developed successfully. This conclusion is reinforced by the facts that (1) the 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[18] and (2) time is running short for these projects to be developed with an on-line date before the end of 2016 to qualify for the higher ITC. Utility applications such as this one are creating great regulatory uncertainty and thus are helping to "run out the clock" for the solar projects in the PacifiCorp pricing queue.

In addition, even if a project can secure a 20-year PPA from PacifiCorp, it may not be successfully developed, for a variety of reasons that can include failure to gain or maintain site control, local or state permitting difficulties, and an inability to secure financing. PacifiCorp concedes in discovery that, since 2007, only 75% of QF projects that have executed contracts have been successfully developed[19] and that, among its recently-signed QF PPAs in Oregon, one PPA is likely to terminate.[20]

[16] 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.".

[17] 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."*

[18] 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.

[19] PacifiCorp response to Sierra Club Data Request 1.4(a) included in Exhibit SC-2.

[20] PacifiCorp response to Sierra Club Data Request 1.14 included in Exhibit SC-2.

Q. How does the current avoided cost methodology in Oregon affect the development of QF projects?

A. It is a matter of basic free-market economics that, as prices fall, fewer projects will be built. In my judgment, the Commission-approved avoided cost method appears to be working as intended. As more solar capacity is added, the avoided cost price has and will fall based on PacifiCorp's capacity position and future need. It is simply not true that the Commission's avoided cost methodology fails to consider the future need for new capacity – as the need for capacity is pushed further out into the future, the avoided cost price drops. At this point, based on the pricing evidence discussed above, it is unlikely that there will be further significant development of solar QFs in Oregon in the near future. If by some chance additional solar can be developed at the new, lower prices that reflect the utility's current need and avoided costs, then Oregon's consumers will benefit from adding new renewable generation at even lower costs, at prices comparable to or better than solar PPAs anywhere else in the U.S. The Commission should continue to allow the market for renewable generation to function in Oregon, rather than stepping in to change a critical element of that market. I share the perspective of the Idaho Commission's staff, which that commission cited in its Order 32697:

> "[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."[21]

Q: Mr. Griswold's testimony alleges that long-term QF contracts are too risky for Oregon ratepayers. He discusses at length the company's policies with respect to hedging in short-term commodity markets (which generally 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.[22] Do you agree?

A: No. The problem with this discussion is that QFs are not short-term energy commodities such as a 30-day spot gas supply, but are long-term, steel-in-the-ground

[21] Order 32697 at p. 19, citing Tr. at 1090.
[22] Griswold testimony, at pp. 15-23.

power plants with 20+ year lives. There is no liquid market for QF projects in the same way that there are markets for spot gas at Opal, Wyoming or for day-ahead on-peak power in the Mid-Columbia (Mid-C) market. If the utility subjected the generation resource acquisitions that it owns to its own short-term hedging policies, it could never receive more than 36 months of assured rate recovery for the non-fuel capital and operating costs of a power plant. I doubt that the Company would build a power plant under those conditions, nor can a QF developer.

Mr. Griswold complains that, if the Company were to consider a longer-term hedge such as a fixed-price QF contract, the utility generally would require more detailed review and more extensive planning than it is allowed to devote to a must-purchase QF contract. In addition, the utility would procure the long-term resource through a more competitive procurement process.[23] Fundamentally, this is a complaint about the limitations which the PURPA must-purchase obligation imposes on the state's procurement process for long-term utility resources. Fortunately, as discussed in more detail below, the EPAct of 2005 and the FERC have already solved this problem, by providing states with a means to remove the PURPA must-purchase obligation if a state can show that QF resources have a comparable long-term market for their energy and capacity. What states cannot do under the PURPA paradigm is to treat QFs as short-term resources, frustrating QF development and the intent of PURPA by limiting them to short-term power sales.

Q: Do you agree with Mr. Griswold that because QF projects do not undergo the "same extensive IRP process" as utility-owned resources, they should be limited in the contract term which they receive, in order to reduce ratepayer exposure to pricing risks?[24]

A: No. The QF procurement process differs from that for utility-owned resources, as a result of the PURPA must-purchase obligation, but in my opinion the QF process also represents a thorough screening of potential QF resources. First, the Commission

[23] *Ibid*., at pp. 17-20.
[24] Griswold testimony, at p. 25, line 18, to p. 26, line 7.

approves an avoided cost methodology developed through a fully litigated Commission docket with multiple parties. Second, the utility's comprehensive IRP process establishes a future resource plan, including the timing of the utility's future need for generation, and models the utility's avoided energy and capacity costs associated with that plan. This extensive process, combining both the IRP and the Commission's approved avoided cost methodology, establishes the level and timing of the combined capacity and energy payments unique to each proposed QF, and has regular updates to ensure accurate information as time moves forward. Importantly, Oregon's method for calculating avoided costs also relies on the utilities' IRPs and thus provides the same assumptions, uses the same tools, and is subject to the same robust scrutiny as utility proposals to build owned resources. Finally, as more renewable QF generation is added, avoided costs will decline, due to changes in the utility's capacity position and the impacts on market prices of more zero-variable-cost generation. Ultimately, the avoided cost price will fall to a level that no longer allows successful QF development. As discussed above, we may be at that point in Oregon today.

Q: Are there ways in which QF contracts reduce risks for ratepayers compared to utility-owned resources?

A: Yes. QF contracts include performance guarantees by the QF that are more stringent than those which apply to a utility-owned plant. QFs must actually deliver energy within the performance bounds contained in the contracts to receive any payments. They are not paid if the QF project is never built or fails to operate correctly. The only element of the contractual payment which is guaranteed is the rate. This is substantially riskier for the QF project than an investment in generation assets is for the utility. Once a utility generation asset is approved for rate recovery through the utility's rate base, the utility will recover its costs, including the necessary fuel costs, and earn a return, even if the plant is out of service or does not perform with the efficiency originally advertised. The only circumstance in which this assured return will be reduced is the infrequent event that the Commission finds, typically after a lengthy regulatory process, that the utility's operation of the plant was imprudent or unreasonable. No such finding is required to deny payment to a QF project: if the QF fails to deliver per the contract, it is not paid. Ratepayers benefit from the QF's assumption of this greater level of operating risk, compared to utility-owned generation. In addition, the QF also bears all of the risks associated with future environmental compliance costs associated with its project. As we have seen with respect to coal resources, these costs can become very significant as environmental standards change.

IV. PACIFICORP'S PROPOSAL WOULD VIOLATE PURPA BY PREVENTING QF DEVELOPMENT

Q. How would PacifiCorp's proposal affect the ability of QF's to develop projects in Oregon?

A. By reducing the PURPA contract term to three years, the Company is essentially asking the Commission to prevent most future PURPA contracts in Oregon, particularly for renewable QFs, by shortening the contract term in a manner that would almost certainly prohibit renewable QF developers from obtaining financing.

Instead of the draconian step of shortening the term of QF contracts, which would close the long-term wholesale market for renewable QF resources in Oregon, there are other steps which the Commission and the state of Oregon could take to allow greater control over the acquisition of renewable resources.

Q: Please elaborate.

A: The Oregon Legislature, with the assistance of this Commission, could expand and extend the state's current RPS program. This could allow the state's major investor-owned utilities, PacifiCorp and Portland General Electric, to show the FERC that the state has created a long-term wholesale market for additional renewable generation to serve consumers in the state. This showing would be essential if the state's utilities were to petition the FERC for relief from the PURPA must-take requirement under Section 210(m), as it was for the California utilities.

More generally, RPS programs provide an outlet for renewable development that is under direct state control by the Legislature and the Commission. For example, in

California, each year a regulated utility must submit an RPS Procurement Plan to the California Public Utilities Commission for approval; these plans set forth in comprehensive detail – fully comparable to an IRP – how the utility will procure adequate renewable generation to meet the RPS program goals. The California utilities procure RPS power under long-term contracts using detailed, competitive requests for proposals (RFPs) that are very similar to the process that PacifiCorp follows in Oregon to procure long-term resources. These plans and RFPs provide the state with comprehensive oversight over renewable development in California – exactly the type of planning control that states may lose from the federal PURPA must-purchase mandate. Furthermore, in a state that has an active RPS program, when the RPS goal is reached, renewable developers and proponents need to ask the state legislature or regulatory commission to increase the program target. For example, this has already occurred several times in California, as successive RPS goals have been reached.[25] In sum, an active RPS program can be an integral part of a showing under Section 201(m) of PURPA to end the must-purchase obligation, which would allow control over renewable development largely to pass to the state, and away from the federal PURPA requirements.

Q: Has the state of Oregon or the electric utilities serving Oregon taken steps that might allow the utilities to petition FERC for relief from the PURPA must-purchase requirements?

A: I am not aware of any such steps that have been taken in Oregon. Nonetheless, these options exist for greater state control over renewable resource development, and examples of how to pursue them are available in many other states with active RPS programs. However until Oregon pursues such a course, the longstanding PURPA framework, including the must purchase requirement, will remain a feature of the energy landscape in Oregon, and the changes to Oregon's PURPA program that PacifiCorp is

[25] 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 33% by 2020. The California Legislature has just passed, and Governor Brown has signed, a further increase to 50% by 2030 (SB 350). 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.

requesting in this docket must be assessed in terms of whether they satisfy the longstanding goal of the PURPA program to promote the development of QF generation at avoided cost prices.

Q: Does the historical record of renewable QF development in Oregon show that successful development of such QFs requires long-term contracts?

A: Yes, it does. Most of the renewable QF projects successfully developed in Oregon or in PacifiCorp's multi-state service territory have obtained power purchase contracts with terms of at least 15 years. Of PacifiCorp's 135.7 MW of existing operational renewable QF contracts in Oregon that do not burn fossil fuels or biomass,[26] the weighted average contract term is 20.2 years. Specifically, 99.9% of this capacity operates under contract terms of 15 years or longer. There are no operating wind, solar, or hydro QFs in Oregon that date from the period from 1996 to 2005 when the QF contract term was limited to no more than 5 years – 65 MW of today's operating fleet of such QFs were developed before 1990; the remainder came on-line in 2009 or later. Further, 100% of the 252 MW of wind and solar contracts for Oregon projects that PacifiCorp has signed in the last several years (but that are not yet on-line) have 15- or 20-year terms, with an average term of 18.3 years.[27]

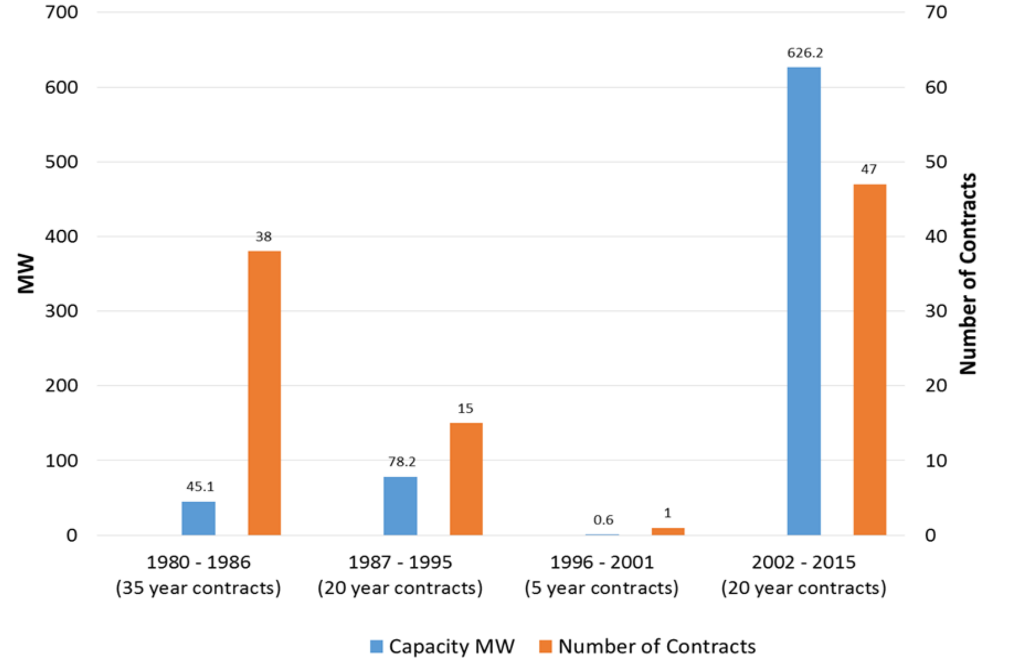
This history is not surprising – wind, solar, hydro, and geothermal projects have no fuel costs but are capital-intensive, and, in my decades of experience I have observed that long-term contracts are essential for such projects to access financing on reasonable terms. This need for long-term assurance of capital recovery is the same for QFs as it is for a utility that proposes to build a new power plant and seeks Commission approval for long-term recovery of the plant's costs by including them in rate base. A utility would not build a new generating plant if it were only assured of cost recovery through rate base for three years, and had to re-justify the plant's cost-effectiveness every three years. This history shows that, without long-term, 15- or 20-year contracts, few if any QFs will be developed in Oregon.

[26] In other words, QFs using all technologies except natural gas-fired cogeneration and biomass or biogas.
[27] Based on data from PacifiCorp response to Sierra Club Data Request (DR) Nos. 1-12 and 1-13.

Q: Have other states had similar experiences, in terms of the relationship between QF development and the available contract term?

A: Yes. Idaho provides one example. The following figure shows that virtually all of the QFs developed on the Idaho Power system date from periods when that state has allowed QF contracts of 20 years or longer.

Figure 1: Idaho Power Renewable QFs by Contract Term



California offered 20- to 30-year PURPA contracts in the 1980s, with renewable QFs provided fixed energy and capacity prices for up to the initial ten years of the contract, and fixed capacity prices for the full contract term. Approximately 5,000 MW of renewable QF generation was developed in the state in the late 1980s; most of this capacity is still operating today and now is the lowest cost generation available to the state's RPS program. This development ceased when the long-term contracts were suspended in the late 1980s (short-term contracts remained available), and did not revive until after the enactment of the California RPS program in 2004, which again offered the QF market long-term contracts of up to 25 years.

Finally, the recent active development of solar QFs in North Carolina, Idaho, Utah, and Oregon has been founded upon the availability of 15-to-20 year contracts at known, fixed prices.

Q: Have any state utility commissions recently denied a utility request to reduce the term of PURPA contracts?

A: Yes. Of course, less than two years ago, this Commission declined to change the term of QF contracts, in Order 14-058 in UM 1610.

In addition, in the past two years, utilities in North Carolina, Idaho, and Utah have asked regulators in those states to reduce the maximum term of QF contracts. In all three states, utilities have strenuously claimed to be overwhelmed by solar QF development, similar to what the Company is alleging to exist in Oregon today. PacifiCorp was among the requesting utilities in Idaho, and was the sole requesting utility in Utah. The two commissions that have issued decisions on these requests – North Carolina and Idaho – reached different outcomes.

Last year the utilities in North Carolina asked the commission in that state to shorten the term of PURPA contracts to a maximum of 10 years, a reduction of 5 years from the maximum of 15-year term that in recent years has resulted in significant development of solar QFs in that state. The North Carolina Utilities Commission rejected the utilities' request, finding that the term of QF contracts needs to be long enough to enable QF projects to be financed:

> 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.[28]

Conversely, utilities in Idaho, including PacifiCorp, asked the Idaho Commission earlier this year to reduce the maximum 20-year term of PURPA contracts to two years. The Idaho commission granted the request to shorten the contract term to two years, finding that PURPA does not require long-term contracts and that a shorter contract term will better align the avoided cost prices in QF contracts with market prices and the utility's actual avoided costs.[29] The Idaho commission did not address whether long-term contracts are necessary to allow QF projects to be financed; nor did the Idaho commission address the evidence on the significant ancillary benefits of QF resources, such as is presented in Section VI of this testimony. Finally, the Idaho PUC declined "to treat QFs similarly with utility resources," and found Idaho's past record of QF contracting showed that it had made "significant advancements" to "encourage the development of renewable resources,"[30] even though the evidence, as shown in the figure above, is that all of this progress has occurred when Idaho had made available QF contract terms of at least 20 years.

[28] 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."

[29] Idaho Public Utilities Commission, Order No. 33357 in Case No. IPC-E-15-01 *et al.*, issued August 20, 2015, at pp. 11-12 and 22-23. The order also finds that shorter QF contracts do not prevent a QF from selling power under a series of shorter-term contracts, although the Idaho commission did not adopt proposals for 20-year contracts with periodic price re-openers, such as a proposal from the Sierra Club and the Idaho Conservation League for the energy portion of the fixed price to be re-priced after 10 years. See pp. 23-24.

[30] *Ibid.*, at p. 24. The Idaho order does allow a QF that signs a series of shorter-term contracts to retain the date of capacity deficiency that existed at the time of its initial contract, presumably allowing such a QF to receive capacity payments after that date, if it remains under contract. This recognizes that a QF would be likely never to reach a year of capacity deficiency if that date re-sets further into the future every time the QF signed a short-term contract, even though the QF may provide significant ongoing capacity to the utility. See pp. 25-26.

Q: Why should the Commission continue to require PacifiCorp to make contracts with terms of at least 15 years available to QFs?

A: Fundamentally, a contract term of this length is necessary to realize PURPA's policy goal of supporting QF development. The Company is correct that "[a] critical element of the utility's must-purchase requirement under PURPA is the contract term."[31] According to the Company , "[t]he term is critical because FERC generally requires a utility to lock in forecasted avoided cost rates for the entire contract term." It is also critical because capital-intensive solar and wind projects cannot be financed without long-term contracts. In fact, contract term is a decisive factor in QF development – as discussed above, states have successfully encouraged the development of QFs when they have offered long-term (15-year to 35-year) contracts at known avoided cost prices. In contrast, when only short-term (5 years or less) contracts have been available, relatively few QFs are developed.[32] The history of QF development cited above, including on the PacifiCorp system, fully supports this conclusion that renewable QFs (except perhaps biomass) require long-term contracts to be successfully developed.

Developers of solar projects and other renewable QFs will not be able to obtain financing for their projects if all that they can show a lender is that they have a customer for the power for just the first three years of a 25-year project life. In addition, a contract price that is based on just the next three years of avoided costs often will be lower than a price based on the next 10 to 20 years of expected avoided costs, because the market presently expects avoided costs to increase over time. For example, based on PacifiCorp's current Schedule 37 prices, the levelized avoided cost price for a three-year solar contract beginning in 2017 is 45% below the average price for a 15-year contract. As a result, limiting the term of QF contracts to three years would reduce significantly the contract price, thus making uneconomic QFs that might be developed at avoided cost prices with a long-term agreement. As a result, it is questionable whether PacifiCorp's

[31] Application at p. 5.
[32] The few QF projects that may be developed with shorter-term contracts are cogeneration and biomass QFs that have significant fuel costs; these QFs may prefer shorter-term contracts whose prices are more closely linked to the fuel markets which are the most important input cost for these technologies. However, generally I would expect that CHP QF projects represent significant capital investments that require long-term contracts to be reasonable investments.

proposed three-year maximum term for PURPA contracts adequately supports QF development in its service territory, as PURPA requires.

Q: Is there a third reason why the Company's request should be rejected?

A: Yes. As I will discuss in detail in the next section, there are many benefits of this new renewable generation that are not included in the avoided cost price, and that make QF generation a good deal for Oregon ratepayers. The Commission should reject the Company's proposal to turn its back on these benefits by reducing the term of these PURPA contracts, a step that essentially would relieve the utility from its PURPA obligations.

V. RATEPAYER BENEFITS FROM FIXED-PRICE PURPA GENERATION

Q: PacifiCorp alleges that the continued availability of long-term contracts will inflate the power supply costs borne by its customers.[33] Do you agree?

A: No. As I will explain below, PacifiCorp's customers will realize significant additional net benefits from the utility's purchase of renewable generation under PURPA, benefits that are not included in the avoided cost price. These include:

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

Generally, it is important to remember that the prices in these contracts are set based on the best available estimate of the utility's <u>avoided costs</u>, that is, the costs which the utility would incur if it did not buy from the QF, but instead generated the power itself or purchased it from another source. Assuming that these estimates are accurate,

---

[33] Application, at p. 21, also, generally, pp. 20-25.

then by definition these contracts will not have an adverse impact on PacifiCorp's customers, because the utility's costs will be no different than if they had not purchased this generation. Estimates of how additional solar or wind contracts would increase the Company's PURPA expenses are irrelevant assuming that the proposed contracts are priced at the utility's avoided costs, because the increased PURPA expenses will be offset by corresponding reductions in PacifiCorp's costs for the other resources that the new PURPA generation will replace. Customers will be at least indifferent to the purchase of the PURPA generation, which is the basic tenet of PURPA, and are likely to be better off, as a result of the additional benefits discussed below.

Q: Please respond to PacifiCorp's assertion that this additional PURPA generation will adversely impact customers.[34]

A: PacifiCorp argues that customers may be harmed if avoided costs turn out to be lower than forecasted. In discovery, the utility reiterated testimony asserting 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.[35] Of course, the Company also conceded that ratepayers will <u>benefit</u> by a comparable amount if the Company's actual avoided costs over the next 20 years are 10% <u>higher</u> than now forecasted.[36] Presumably, there is a roughly equal chance of each outcome, and the expected outcome is exactly equal to the forecasted avoided cost on which QF prices are based.[37] Mr. Griswold's concern is that these fixed-price contracts amount to "speculative trading,"[38] placing ratepayers in a

[34] Application, at pp. 23-25.
[35] PacifiCorp Response to Sierra Club Data Request 2.14, included in Exhibit SC-2.
[36] *Ibid*.
[37] 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 "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.
[38] Griswold testimony, at p. 22.

position where they win if future energy market prices are higher than expected, and lose if they are lower than anticipated.[39] Mr. Griswold's entire assertion that ratepayers will be harmed by these contracts thus boils down to his own speculative bet that future avoided cost will be 10% lower than forecasted today – speculation that departs from the utility's own best forecast on which its avoided costs are based.[40]

In fact, for the reasons discussed below, the solar contracts will offer other benefits that are not included in avoided cost prices and that will result in <u>lower</u> power supply costs for PacifiCorp's customers.

A. Renewable value / avoided carbon mitigation costs

Q: Are there benefits to PacifiCorp's customers in Oregon from additional renewable PURPA generation?

A: Yes. PacifiCorp could use this generation for compliance with the Oregon RPS, although its 2015 IRP does not show a need for Oregon renewable energy credits (RECs) for RPS compliance until 2027.[41] Even if the RECs from the new renewable QF s are not immediately needed for RPS compliance in Oregon, PacifiCorp could sell any RECs that it purchases along with this power. The revenues from these sales would be a benefit for ratepayers. PacifiCorp projects that the group of recently-contracted renewable QFs on its six-state system will provide its utilities with about 1,000,000 MWhs per year of RECs systemwide. A portion of these REC sales revenues will benefit Oregon ratepayers.[42]

---

[39] 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."

[40] Mr. Griswold also compares, at page 29, the expected future costs for PacifiCorp's QF resources ($64.13 per MWh) over the next decade to the 10-year forward price for market generation at Mid-Columbia ($35.27 per MWh). This comparison of long-term QF prices to short-term market prices is misplaced, as it does not include the value of the firm generation capacity that existing QFs have displaced, the value of the renewable attributes of the renewable QF capacity, the possible transmission capacity and line loss savings from QFs that are sited close to load, as well as the other benefits of QF generation discussed in this section.

[41] 2015 IRP, at p. 10 (Table 1.3, Action 1a).

[42] PacifiCorp Response to Sierra Club Data Requests 1.3 and 1.27, included in Exhibit SC-2.

Q: Does PacifiCorp receive significant revenue from these REC sales that benefit its ratepayers?

A: Yes. These revenues for 2010-2014 are shown in the following table, as well as the average REC price received:

Table 1: *PacifiCorp 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

As shown in the table, REC prices can fluctuate significantly based on the demand for RECs, the supply of RECs on offer, and the compliance status of utilities in the various western states with active RPS procurement programs.

It is my understanding that a portion of the revenues from these REC sales is returned to consumers in Oregon. Based on this track record, and assuming (1) a long-term price of $10 per MWh for RECs, [43] (2) PacifiCorp receives 32% of the RECs from these projects,[44] and (3) a solar capacity factor of 27%,[45] an additional 500 MW of solar contracts could add $3.8 million per year in additional REC revenues.

Q: Will PacifiCorp ratepayers also benefit if the utility retains and retires the RECs associated with this generation?

A: Yes. If the RECs are retained and retired, then PacifiCorp can claim a corresponding share of the carbon emission reductions associated with this power. The

[43] 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.
[44] 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 PacifiCorp Response to Sierra Club Data Request 1.27, included in Exhibit SC-2.
[45] See PacifiCorp Response to Sierra Club Data Request 1.27.

value of these reductions in carbon emissions from 500 MW of new solar QFs is about $10 million per year over the life of these resources, or about $8.66 per MWh.[46] These benefits can be considered a proxy for the future compliance costs that the utility may avoid by increasing its purchases of renewable generation.

B. Hedging benefits

Q: PacifiCorp argues that it is too risky for consumers to commit to long-term fixed-price contracts. Do you agree?

A: No. With any fixed-price power purchase contract – and with any significant capital investment by the utility in generation or transmission – there is always a risk that the alternatives will prove to be less expensive over the long-term. This is a risk that consumers bear with PURPA contracts, with other purchases in wholesale markets, and with the alternative of utility-owned fossil-fuel plants whose capital costs are largely fixed once they are approved for cost recovery through rate base and whose fuel costs are subject to significant market risk. PacifiCorp complains that the prices or terms of QF contracts cannot be modified once they are signed, yet it is also difficult to modify the costs for utility-owned generation included in the rate base once they have been authorized and the plant built. And ratepayers become exposed to the market risk associated with the fuel costs for the utility-owned units.

Utility-owned generation, and in particular coal units, also face the risk that long-term capital costs for rate-based units could increase over time because additional capital expenditures may be necessary to continue to operate the units in compliance with more protective laws and regulations. Utilities also sign long-term contracts for fuel (such as coal) or for fuel delivery (such as long-term natural gas pipeline capacity contracts). Such expenses would either increase the overall costs of the utility-owned power plant, or force

[46] This assumes that 500 MW of potential solar contracts displace gas-fired generation at a heat rate of 8.0 MMBtu per MWh, and uses the carbon emission 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). See 2015 IRP, at pp. 146-147 (Figure 7.6).

the utility to deal with stranded assets. Both scenarios could increase costs to customers in the long-term, which would not happen for a fixed-price QF contract.

If it is too uncertain, too risky, and "speculative trading" to forecast avoided cost prices for 20 years, then by the same argument it would also be too risky to evaluate the merits of the alternatives to QF power (such as a new utility-owned resource or retrofitting an existing fossil fuel plant with expensive pollution controls), or even to make decisions based on the long-term projections in an IRP.

The North Carolina commission recognized this in its recent avoided cost order, concluding that the uncertainties in future energy markets will impact ratepayers regardless of whether the utility contracts with QFs at avoided cost or builds its own resources:

> 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.[47]

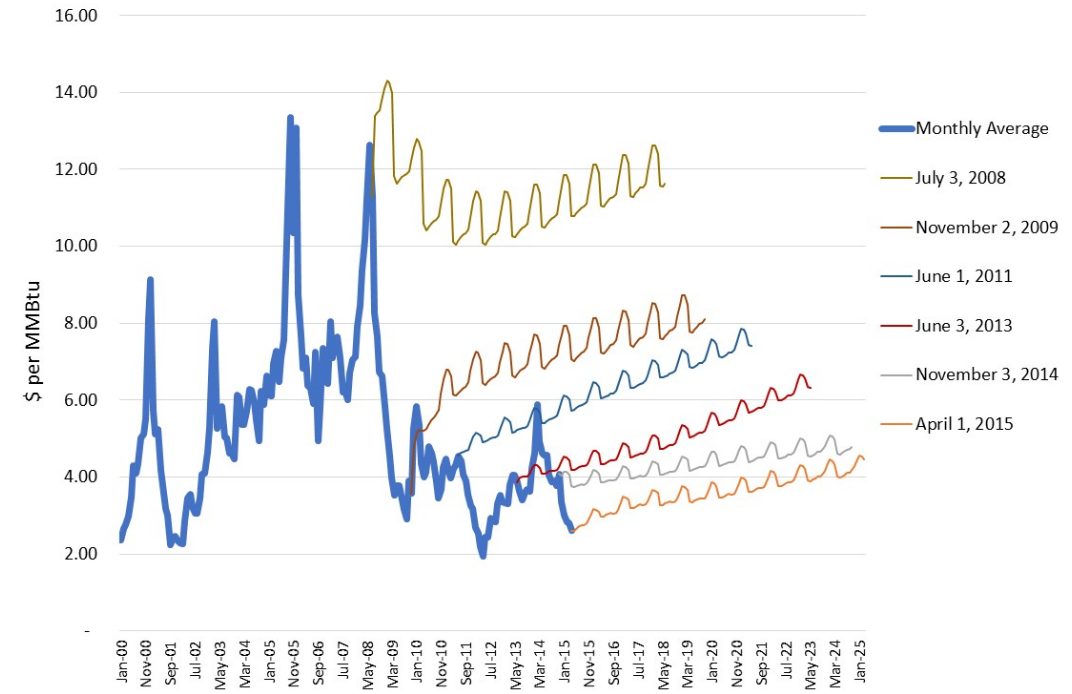
Q: Do fixed-price contracts for renewable generation provide a benefit to consumers as a hedge against future uncertainty and volatility in energy and fossil fuel markets?

A: Yes. The alternative to the PURPA contracts is reliance on marginal utility fossil generation (mostly natural gas-fired) and/or market purchases, whose prices also are influenced heavily by gas prices. The value for ratepayers of hedging this exposure is simple: fixed-price generation protects against periodic spikes in natural gas prices. Such spikes have occurred regularly over the last several decades, as shown in the plot of historical benchmark Henry Hub gas prices in **Figure 2** below.[48] Hedging against these

[47] North Carolina Avoided Cost Order, at p. 21.
[48] Source for Figure 2: Chicago Mercantile Exchange data.

extreme events can be very beneficial for ratepayers.

Figure 2: Henry Hub Market Prices
Monthly Average and Selected 10-Year Forward Market Prices



Fixed prices also hedge against market dislocations or generation scarcity such as was experienced throughout the West during the California energy crisis of 2000-2001 or as is occurring today with the extreme drought in California and long-term, drier-than-normal conditions elsewhere in the West.[49] Obviously, there is a risk that consumers may not benefit if future prices turn out to be lower than anticipated, but, if that happens, consumers will enjoy the low prices for the portion of their needs that is not hedged.

Many utilities, including those in Oregon, conduct risk management programs that include hedging that uses a variety of forward market instruments and that is designed primarily to reduce the near-term volatility of their short-term fuel and purchased power expenses. Generally, these programs focus on reducing volatility only

[49] For example, in 2014, the 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. This is 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-renewable-energy-provider-in-california.

in the next 1-3 years, as the forward markets are most liquid in the near-term and there are substantial transaction costs associated with long-term hedges in financial markets, if such hedges are even available. However, utilities regularly engage in long-term hedging through their resource portfolios, and companies such as PacifiCorp are careful to evaluate their overall risk position as including both their short- and long-term positions in both natural gas and power. Significantly, PacifiCorp's discussion of its hedging program in its 2015 IRP emphasizes how its long position in the power market can function as a hedge against its short position in natural gas, and concludes that "[t]his has the effect of reducing the amount of natural gas hedging that the Company would otherwise pursue."[50] This is exactly the hedge represented by the fixed-price QF contracts at issue in this case. In addition, other observers have noted that long-term, fixed-price contracts for renewable generation provide utilities with a means not available in the financial markets to hedge their long-term exposure to gas and power markets, and thus could replace a portion of their current budgets for risk management.[51] A number of studies have quantified these hedging benefits. In the West, Public 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.[52]

C. Market Price Mitigation

Q: Will an increasing penetration of new renewable generation in Oregon and the West have an impact on energy market prices?

A: Yes. This new solar generation will increase the electricity supplies available to PacifiCorp. Because this generation is must-take (and has zero variable costs), it will

[50] 2015 IRP, at pp. 246-247.

[51] 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/2012-07_WindNaturalGasVolatility.

[52] 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.

displace the most expensive fossil-fired or market resources that the Company would otherwise have generated or purchased. The addition of this local generation will reduce the demand which the utility places on the regional markets for electricity and natural gas. With this reduction in 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.[53] As discussed in PacifiCorp's IRP, the Company expects to have a short position in these markets for many years into the future.[54] This "market price mitigation" benefit of renewable generation is widely acknowledged, and has become highly visible in markets that now have high penetrations of wind and solar resources. The magnitude of these benefits will depend on the overall amount of renewables on the western grid.

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

A: Yes. The National Renewable Energy Laboratory (NREL) and GE Consulting have undertaken the Western Wind and Solar Integration Study (WWSIS), a major, multi-phase modeling effort to analyze much higher penetrations of wind and solar resources in the western U.S.[55] This modeling included analysis of the impact of increasing solar penetration on market prices in the West; the results for spot prices in Arizona are shown in the figure below. The high penetration solar cases (15% to 25% penetration) in the WECC result in 10% to 20% reductions in spot market prices.

---

[53] 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.

[54] 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.

[55] 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.

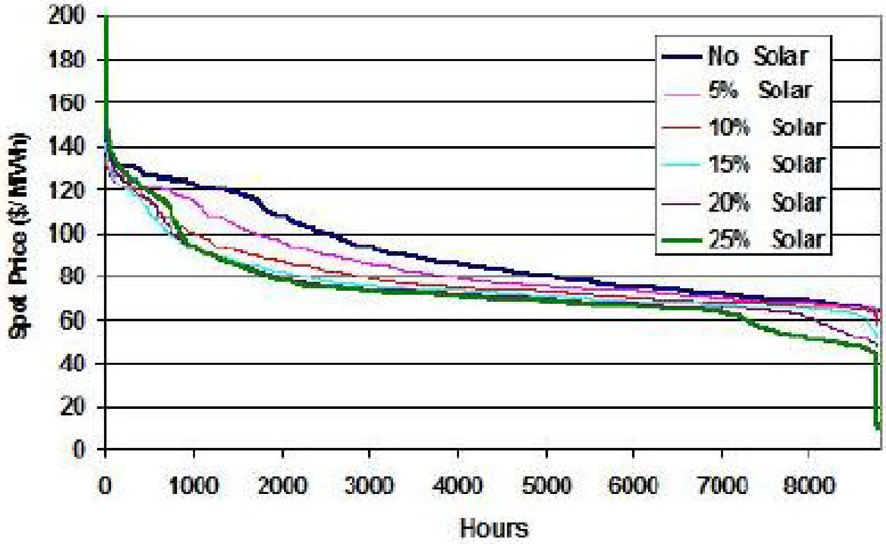


Figure 19 – Arizona Spot Price Duration Curves.

D. Capacity optionality

Q: Will these additional solar resources provide new generating capacity in PacifiCorp's service territory?

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] Thus, each additional 100 MW (AC) of solar resources would add 34 MW of capacity. All of this capacity would be internal to PacifiCorp's system, and will not require additional out-of-state transmission capacity to be deliverable to its customers in Oregon.

Q: Initial results from PacifiCorp's 2015 IRP show the next need for capacity is not until 2028, when the 816 MW of approved PURPA contracts are included in the resource stack.[57] Is there a potential benefit if additional solar and wind capacity comes on-line before it is expected to be needed under the utility's current IRP?

A: Yes. PacifiCorp has no immediate need for capacity based on its current IRP, and this lack of need is priced into the solar contracts, both those that the utility has signed

[56] 2015 IRP, at p. 405.
[57] *Ibid.*, at 4.

recently and those that it might sign in the near future. This assumed lack of need results in lower prices in these contracts. However, events may occur that accelerate PacifiCorp's need for capacity, such as the early retirement of a portion of the utility's coal capacity, which could occur for a variety of reasons, including the cost of additional emission controls and/or compliance needs related to the federal government's Clean Power Plan. The possibility of additional renewable contracts provides PacifiCorp with an essentially free option to replace existing capacity prior to the current date when capacity is needed. This provides customers in Oregon with insurance, at no cost, against events which might challenge reliability and cause a new need for capacity.

E. Local economic benefits

Q: Will there be economic benefits for Oregon from additional development of the state's indigenous resources?

A: Yes. The construction of each additional 500 MW of solar generation in Oregon would represent an investment of $1.5 billion in the state, assuming a capital cost of $3,000 per kW.[58] Not all of this money will be spent in Oregon, of course, but there would be significant short-term employment benefits during construction as well as permanent employment operating and maintaining these facilities, as well as royalties to landowners and property taxes to local communities. Significantly, because these facilities will be located in Oregon, the economic benefits are more likely to accrue locally than if these were out-of-state power plants or power purchases from regional markets.

F. A window of opportunity to procure low-cost solar

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

A: Yes. Natural gas prices today are quite low in historical terms, particularly for longer-term forward contracts. Figure 2 above also shows several examples of the 10-

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

year forward price for natural gas at the Henry Hub in recent years. This shows that today's avoided costs are relatively low in historic terms. New sources of clean energy are becoming competitive even with these low prices. Put simply, if today's independent QF developers can meet or beat this avoided cost, then it will be a good deal for ratepayers. In addition, the 30% federal investment tax credit (ITC) expires at the end of 2016, after which it will drop to 10%. As a result, the levelized cost of solar generation is expected to rise significantly for several years beginning in 2017, by 25% to 33%, until cost reductions for this technology can offset the loss of this significant incentive.[59] Now is an opportune moment to purchase solar generation at contract prices that may not be available for a considerable period after 2016.[60]

VI. SYSTEM RELIABILITY

Q: Are you concerned that PacifiCorp would have difficulty integrating additional intermittent solar generation into its system?

A: No. The integration of higher levels of wind and solar resources presents a challenge to utilities and grid operators across the U.S., not just in the West. In recent years, numerous studies have been conducted on the operational and system reliability impacts of the increasing penetration of variable renewable resources. For example, in the West the WWSIS showed the ability to integrate levels of wind and solar penetration far in excess of today's levels, provided these variable resources could be balanced on a sub-hourly basis over a large geographic footprint, with more accurate forecasts of variable resource output.

---

[59] Using a generation cost tool developed for the WECC, the drop in the federal ITC could add $15 to $20 per MWh (+25% to +33%) to solar contract prices after 2017. See 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. This calculation assumes a $2,000 per kW utility-scale solar PV capital cost in 2017 for a 20 MW solar project in Oregon.

[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.

Most notably and most recently, PacifiCorp has joined with the CAISO to create a new energy imbalance market (EIM) that is intended, among other benefits, to implement the key findings of the WWSIS – balancing wind and solar resources more efficiently on a sub-hourly basis over a larger geographic footprint. 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.[61] NV Energy and Puget Sound Energy will be joining the EIM in October 2015 and October 2016, respectively. In essence, the EIM promotes the more granular and efficient exchange of power among the participating control areas. Thus, PacifiCorp should be able to integrate higher levels of solar generation on its system.

Q: Does this conclude your direct testimony?

A: Yes, it does.

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

Exhibit SC-1

Resume of Patrick G. McGuire

PATRICK G. MCGUIRE
Energy Policy Advisor

Mr. McGuire is energy policy advisor with the consulting firm Crossborder Energy. Crossborder Energy provides economic consulting services and strategic advice on market and regulatory issues concerning the natural gas and electric industries. The firm is based in Berkeley, California, and its practice focuses on the energy markets in California, the western U.S., Canada, and Mexico.

Mr. McGuire has worked for Crossborder Energy since 1992, and has participated in the most of the firm's analytic work. From 1989 through 1992 he was employed by Sierra Energy and Risk Assessment, an energy consulting firm in Roseville, California with a focus on electric utility production cost modeling.

AREAS OF EXPERTISE

- *Mathematics, Economics, and Computer Programming.* Applies micro-economic theory, mathematics, and computer programming and modeling skills to the firm's study of regulatory and public policy issues in the natural gas and electric industries. Responsible for drafting much of the firm's spreadsheet analyses used in the firm's work products. Detailed knowledge of relevant computer applications used for consulting studies, primarily Excel and Visual Basic.

- *Electricity Markets.* Modeling and statistical review of electricity markets, with particular emphasis on California's deregulated electricity markets. Has conducted monthly monitoring of California ISO electricity markets since deregulation commenced in April, 1998. Studies have included the impact of cap-and-trade regulation of greenhouse gas emissions on the California electricity market.

- *Natural Gas Markets.* Monitoring and modeling of natural gas markets in the western U.S. Developed a computer model of the North American regional natural gas transportation grid, using a network equilibrium methodology. Provides clients with regular reports on regulatory developments in the California and western U.S. natural gas market.

- *Rate Design and Cost Allocation.* Work has included analysis and forecasts of the impacts of changes in policies and regulations on retail rates for electricity and natural gas. Has worked with long-run marginal cost and embedded cost models used to design natural gas and electricity rates, including natural gas transmission and distribution rates. Has extensive experience with PG&E, SoCal Edison, SoCalGas, and SDG&E rates. Has developed and updated the cost allocation and rate design for a small municipal electric utility in California.

- *Renewables.* Analysis of Renewable Portfolio Standard (RPS) programs, including the impacts of such programs on retail rates. Developed models of revenue requirement impacts of the proposed RPS programs in Florida, New York, and Nevada. Has tracked the historical and forecasted development of the RPS program in California.

- *Net Metering and Photovoltaic Incentives.* Has modeled the Renewable Energy Credit (REC) incentive payments for solar photovoltaic installations, including analysis of state incentive programs for Florida and New York. Has conducted cost/benefit studies, including detailed computer modeling, of the net metering program for residential and commercial solar installations in California. Co-authored state-level studies of Net Energy Metering or distributed solar generation costs and benefits, in four states including California (January 2013), Colorado (September 2013), North Carolina (October 2013), and Arizona (May 2013).

- *Gas-fired Generation Costs.* Has modeled traditional gas-fired generation costs using the Market Price Referent (MPR) approach used in California as the cost benchmark for the RPS program. Has worked extensively on Combined Heat and Power (CHP) issues in California.

- *Contract Analysis.* Performed contract analyses for independent power producers, to address contract restructuring and economic evaluation issues. Served as an expert witness in an arbitration case for a Nevada Geothermal project.

Testimony

- *Vermont Public Service Board.* September 23, 2014 Testimony in Docket No 8010 on behalf of Allco Renewable Energy Limited.

- *California Public Utilities Commission.* March 19, 2003 Testimony in Rulemaking 02-01-011 regarding Direct Access.

Papers

- A Self-Scoring System to Elicit True Cost Multi-Dimensional Bids in an Electric Power Auction, C. B. McGuire and Patrick G. McGuire. Proceedings of the 15th Annual North American Conference of the International Association for Energy Economics, October 1993, pp. 304-314.

EDUCATION

Mr. McGuire holds a B.A. in mathematics from the University of California at Santa Cruz.

EXPERIENCE

Crossborder Energy
Energy Policy Advisor 1992 - Present
Responsible for general analytic support for a broad range of policy and rate design issues in the natural gas and electric industries. Conducted regular reviews of avoided cost energy pricing for cogeneration clients. Assisted in power purchase contract implementation and renegotiation. Monthly market monitoring of the deregulated California electricity and natural gas markets.

Economic review of CAISO, CPUC and FERC policy developments affecting the California market. Application of general analytical policy analysis tools to electricity and gas market issues. Developed computer model of the deregulated California electricity market and a linear programming model of the North American pipeline grid. Developed models of various state-level renewable programs and related solar customer incentives, including net metering.

Sierra Energy & Risk Assessment
Associate Mathematician, 1989-1992
Responsible for maintaining databases and I/O related to electric production cost simulation models. Developed numerous computer models related to the electric industry, including electricity transmission and losses, load profile analysis, DSM program evaluation, and merger cost/benefit analysis.

Exhibit SC-2

Selected Discovery Responses from Pacificorp

UM 1734/PacifiCorp
September 25, 2015
Sierra Club Data Request 1.3

Sierra Club Data Request 1.3

The Company's Application at page 1 identified 338 MW of current PURPA QF contracts in Oregon.

(a) Please provide the percentage share of Renewable Energy Credits (RECs) from these projects that will be provided to PacifiCorp.

(b) Please provide an estimate of the annual MWhs of RECs from the 338 MW of QF projects that will be provided to PacifiCorp.

(c) For the most recent five calendar years (2010 – 2014), please provide PacifiCorp's annual MWhs of REC sales and the annual revenues from these sales. To the extent that the data is available to PacifiCorp, please indicate which state(s) the purchasers of PacifiCorp's RECs used those RECs for RPS compliance.

(d) Does PacifiCorp's indicative pricing for QF contracts include any consideration of the REC values that PacifiCorp will receive from REC sales.

Response to Sierra Club Data Request 1.3

(a) Zero percent of Oregon qualifying facility (QF) power purchase agreements (PPA) were executed as of May 1, 2015. This excludes any projects that received Energy Trust of Oregon (ETO) funding where the projects are required to transfer a portion of their renewable energy credits (REC) through WREGIS to the ETC, who transfers the RECs to the Company for retirement to meet renewable portfolio standards (RPS).

(b) No RECs will be provided to PacifiCorp. Note the comment regarding the ETO stated in subpart (a) above.

(c) The Company's volumes and revenues from sales of RECs 2010 through 2014 are shown in the table below. The Company does not have the data with regards to which states' RPS these RECs were purchased for compliance.

	2010	**2011**	**2012**	**2013**	**2014**
REC Sales (megawatt-hours (MWh))	3,180,995	2,282,416	4,413,723	1,779,553	792,647
REC Sales (dollars ($))	$101,136,015	$72,823,885	$81,263,095	$7,601,287	$4,408,064

(d) No.

UM 1734/PacifiCorp
September 25, 2015
Sierra Club Data Request 1.4

Sierra Club Data Request 1.4

Reference pages 1-2 of PacifiCorp's Application, as well as the Direct Testimony of Bruce Griswold, pages 10-12, discussing executed and proposed PURPA contracts.

(a) Based on PacifiCorp's experience across its system with QF contracts, what is the "success rate" for QFs with signed contracts to actually bring their projects on-line? Express this as a percentage of the historical MWs of signed QF contracts that have resulted in on-line QF projects.

(b) Of the QFs under contract, but not on-line, how many MWs does PacifiCorp expect will be successful at bringing their projects on-line?

Response to Sierra Club Data Request 1.4

(a) On a system-basis since 2007, the Company executed 1,814 megawatts (MW) of qualifying facility (QF) power purchase agreements (PPA). The success rate to reach commercial operation was approximately 75 percent based on QF PPAs that were terminated before reaching commercial operation by either the Company or the QF.

(b) On a system-basis, the Company currently has 1,200 MW of QF PPAs that have been executed but have not reached commercial operation. The Company monitors these QF PPAs through monthly progress reports and communications with the Company during the period after execution through commercial operations and manages the project's compliance with progress milestones in the PPA, as appropriate. The Company does not have an opinion on their probability of reaching commercial operation.

UM 1734/PacifiCorp
September 25, 2015
Sierra Club Data Request 1.14

Sierra Club Data Request 1.14

Please provide an update on whether any of the 12 new QF projects in Oregon totaling 104 MW that have been executed since April 2014 (see page 10 of Mr. Griswold's testimony) have been terminated due to failure to meet project development milestones or due to other factors.

Response to Sierra Club Data Request 1.14

One project has indicated it will self-terminate its power purchase agreement (PPA) but has not provided formal notification. PacifiCorp has not terminated any of the 12 qualifying facility (QF) PPAs.

UM 1734/PacifiCorp
September 25, 2015
Sierra Club Data Request 1.27

Sierra Club Data Request 1.27

Mr. Griswold's testimony, at page 10, states that, "[o]f this total, 51 projects totaling 1,145 MW (58 percent of the total PURPA MWs under contract) have online dates of 2014 or later, further demonstrating the exponential increase in PURPA contract requests and resulting contracts that have occurred in the last two years." Mr. Griswold also references 12 contracts in Oregon totaling 104 MW that have been executed since April 2014.

(a) Please provide the percentage share of Renewable Energy Credits (RECs) from these 1,145 MW and 104 MW of contracted but not on-line projects that will be provided to PacifiCorp.

(b) Please provide an estimate of the annual MWhs of RECs from these 1,145 MW and 104 MW of QF projects that will be provided to PacifiCorp.

Response to Sierra Club Data Request 1.27

(a) One Utah wind project totaling 60 megawatts (MW) provides 100 percent of its renewable energy credits (REC). One Utah solar project totaling 50 MW provides 100 percent of its RECs. Three Utah solar projects totaling 210.4 MW provide 50 percent of their RECs. One Wyoming wind project totaling 80 MW provides 100 percent of its RECs. The rest of the projects provide zero percent of their RECs.

(b) Annual estimate over the contract terms is 1.4 million RECs system-wide including Oregon projects. Assumes 29 percent capacity factor for Utah wind, 38 percent capacity factor for Wyoming wind, 28 percent capacity factor for Utah solar and 27 percent capacity factor for Oregon solar.

UM 1734 / PacifiCorp
September 25, 2015
Sierra Club Data Request 1.28

Sierra Club Data Request 1.28

Please provide PacifiCorp's current assumptions, in its 2013 or 2015 IRP, for how much firm capacity is provided by 1 MW of wind or solar nameplate capacity from a wind or solar project located in PacifiCorp's Oregon service territory. Please provide all supporting documentation for these assumptions.

Response to Sierra Club Data Request 1.28

The peak contribution of one megawatt (MW) of wind project located in on the east side of the Company's system is 0.145 MW. The peak contributions of one MW of fixed tilt and single axis tracking solar project are 0.341 MW and 0.391 MW, respectively. For supporting documents and assumptions, please refer to the Direct Testimony of Company witness, Rick T. Link in Utah Docket 12-035-100 and the supporting work papers. For ease of reference, the testimony and work papers are provided herewith as Attachment Sierra Club 1.28 -1 and Confidential Attachment Sierra Club 1.28 -2. For discussions on the methodology, please also refer to Appendix N to the Company's 2015 Integrated Resource Plan (IRP).

The confidential attachment is designated as Protected Information under Order No. 15-259 and may only be disclosed to qualified persons as defined in that order.

Exhibit SC-3

PacifiCorp Fact Sheet about the new Energy Imbalance Market

California ISO
Shaping a Renewed Future

PACIFICORP

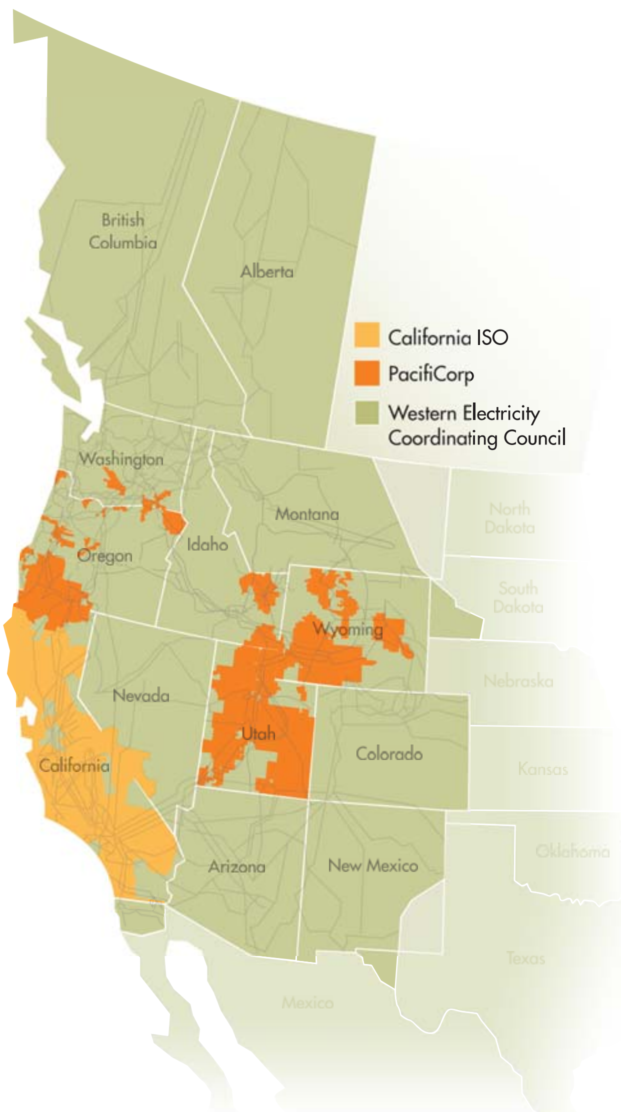
FAST FACTS

Energy imbalance market partnership

The California ISO and PacifiCorp have developed a new partnership that is bringing significant reliability and renewable integration benefits to the West. By developing the EIM between the balancing authorities, a broad array of resources can be shared and economically dispatched through the ISO five-minute market. The regional real-time market service, referred to as an "Energy Imbalance Market" or EIM, optimizes management of the transmission system to balance supply and demand across a larger footprint.

Reliability benefits

The EIM strengthens grid reliability by truing up supply and demand closer to when electricity is consumed, and by allowing real-time visibility across neighboring grids. ISO market systems identify changes in supply and demand and automatically adjust to find the best resource to meet fluctuating demand across a larger region. This, in turn, optimizes the interconnected high-voltage system as market systems automatically handle electricity bottlenecks on transmission lines during the process of managing the flow of electricity.



Renewable integration benefits

As the nation's energy supply becomes more diverse, regional coordination and finely tuned dispatches become more important because of changing weather conditions that produce variability in wind and solar power generation. The EIM improves the ability to manage resource deviations, smoothing out power flows so that renewable energy is effectively integrated onto the grid.

By capturing a wider portfolio of resources, the EIM optimizes available resources reducing the quantity of reserves required to ensure electricity shows up where and when it is needed. By leveraging geographic diversity, the EIM will make it possible to share intermittent renewable resources such as wind or solar during times of under or overgeneration.

Modernized energy dispatching

Deviations in expected supply and demand occur often because electricity is consumed at nearly the same time it is generated. Weather and other conditions can cause a mismatch between available energy versus what is needed by consumers. Balancing authorities have traditionally tried to manage these deviations by relying on manual dispatches and extra power reserves to perform the critical balance of supply and demand essential to grid reliability. As the only real-time energy market in the Western U.S., the advanced ISO market system automatically balance electricity deviations every five minutes by choosing the least-cost resources available to meet demand.

Easy and economical entry and exit

The EIM participants such as PacifiCorp will join the market with a modest set-up cost based on their size and will pay ongoing fees depending upon their participation level. Over the long term, EIM participation is expected to put downward pressure on existing administrative charges for all participants. Additionally, an EIM participant can choose to leave the market at any time.

PacifiCorp and future EIM participants will maintain their existing balancing authority responsibilities, which include the reliability of their own systems, and continue to line up their own operating reserves and serve their customers.

How the concept developed

In 2012, the ISO was asked by a group of public utility commissioners from around the West to provide a conceptual proposal for providing an energy imbalance market. The group of commissioners, called the PUC-EIM, is organized under the Western Interstate Energy Board.

By using the proven platform of the existing market system, the ISO was able to provide a proposal that is highly scalable and allows entities to enter as they choose when they choose. Further, it is attractive to entities like PacifiCorp because the financial commitment is small compared to other options that would include building an EIM from scratch.

Governance

The ISO Board of Governors have established a nine-member Transitional Committee that is developing recommendations to the Board on EIM matters that includes proposing a path for a long-term EIM governance structure. The proposed structure is designed to potentially accommodate two additional members representing EIM entities and is adaptable to address the changing needs of EIM as it matures.

The nomination process for the proposed Transition Committee allowed seven sectors to nominate interested parties. The sectors then rank the full list of nominees for Board consideration. The Transitional Committee is operating in an open, transparent process, supported by ISO administrative and legal staff, when needed.

Current Status

Following Federal Energy Regulatory Commission (FERC) approval of the implementation agreement between the ISO and PacifiCorp in June of 2013, both entities successfully started sharing data and developing models to align system interfaces. Market simulations began in October 2014 and the market went financially binding on November 1, 2014.

Continued stakeholder involvement will be critical to the success of the EIM by offering valuable input and support to expand a market intended to leverage the most effective use of resources in the West.

The ISO committed to providing quarterly informational benefit reports with the first one released on February 11, 2014. It showed the EIM produced estimated benefits of $5.97 million in the market's two months of operation. This is in line with the prelaunch study that found annual benefits would range from $21 million to $129 million.

Las Vegas-based NV Energy will begin participating in the EIM in October 2015.