CASE: UM 1734
WITNESS: BRITTANY ANDRUS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Response Testimony

October 15, 2015

Q. Please state your name, occupation, and business address.

A. My name is Brittany Andrus. My business address is 201 High Street SE Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/101.

Q. What is the purpose of your testimony?

A. My testimony responds to PacifiCorp's Application to Reduce the Qualifying Facility (QF) Contract Term (reduce the fixed price term of both standard and non-standard QF power purchase agreements from 15 years to three years) and Lower the QF Standard Contract Eligibility Cap (Application), filed on May 21, 2015, supported by the testimony of Mr. Bruce Griswold.

Q. How is your testimony organized?

A. My testimony is organized as follows:

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BACKGROUND

Q. Can you explain the history of the current eligibility cap for standard contracts?

A. Federal Energy Regulatory Commission (FERC) rules implementing the Public Utility Regulatory Policy Act (PURPA) require utilities to offer "standard" avoided cost rates to QFs with a nameplate capacity of 100 kW or less, and allow state commissions to establish a higher eligibility cap for standard prices ("Eligibility Cap").[1] In its initial orders and rules implementing PURPA, the OPUC did not impose an Eligibility Cap that differed from the federally-required 100 kW, but did so in 1991.[2]

In 1991, the Commission adopted guidelines for the use of competitive bids to acquire new resources.[3] The Commission noted that QFs could secure a contract with a utility through a competitive bid, or under PURPA.[4] The Commission decided the eligibility cap for standard rates should be increased to 1 MW, stating that "[w]ithout this change, the transaction costs associated with participation in competitive bidding could disadvantage QFs."[5]

Later that year, the Commission modified the Oregon Administrative Rules to establish a 1 MW Eligibility Cap.[6] Staff supported the change, reiterating the concerns identified in the competitive bidding guidelines docket that transaction costs associated with negotiating a power purchase agreement

[1] 18 C.F.R. 292.304(c)(1), (2).
[2] *See* Order Nos. 81-319, 85-742.
[3] Order No. 91-1383 (1991 WL 501921).
[4] *Id.* (1991 WL 501921 at p 10).
[5] *Id.*
[6] Order No. 91-1605 (1991 WL 537183).

could be prohibitive for small QFs and effectively eliminate them from the marketplace.[7]

In 2005, the Commission increased the Eligibility Cap for standard rates and contracting terms to 10 MW.[8] The Commission noted that it "continue[d] to adhere to the policy, as articulated in Order 91-1605, that standard contract rates, terms and conditions are intended to be used as a means to remove transactions costs associated with QF contract negotiation, when such costs act as a market barrier to QF development."[9] The Commission also concluded that "market barriers other than transaction costs also pose obstacles to a QF's negotiation of a power purchase contract[,]" identifying asymmetric information and an unlevel field as such barriers.[10]

Finally, the Commission noted that the need to reduce market barriers must be balanced with the Commission's interest in ensuring that a utility pays a QF no more than its avoided costs for the purchase of energy.[11] The Commission noted that standard contracts do not take into account individual utility's cost characteristics that result in utility cost savings that differ from the standard avoided cost rates.[12] And, the Commission noted that the risk that future costs may differ from the fixed prices in a PURPA contract is "greater" for a large QF than a small one.[13]

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[7] *Id.*
[8] Id.
[9] Order No. 05-584 at 15.
[10] *Id.*
[11] *Id.*
[12] *Id.*
[13] *Id.*

The Commission selected 10 MW as the Eligibility Cap, noting its reliance on Staff's testimony regarding the extent that market barriers prevented successful negotiation of a contract and Oregon Department of Energy testimony indicating that 10 MW represented a point at which the costs of negotiation become a reasonable fraction of total investment costs.[14]

In 2014, the Commission reviewed whether the 10 MW Eligibility Cap should be changed in the Phase I of the still pending Investigation into Qualifying Facility Standard Pricing and Contracting.[15] The Commission relied on testimony from Staff, the Oregon Department of Energy, the Community Renewable Energy Association (CREA), the Renewable Energy Coalition (REC), and Small Business Utility Advocates (SBUA), that "lowering the eligibility cap would deter QF development in Oregon, largely because of the increased transaction costs incurred when negotiating an agreement."[16]

Q. Can you discuss the Commission's past orders regarding the contract term for standard and non-standard contracts?

A. In 1984, the OPUC ordered utilities to offer standard contracts with a term of up to 20 years to QFs 100 kW and less.[17] With respect to non-standard contract terms, the Commission noted that 70 percent of the QFs that had entered into PURPA contracts with PacifiCorp had contract terms of 25-35 years.[18] The Commission ordered utilities to file avoided cost prices for a 35 year period,

[14] *Id.* at 16.
[15] Order No. 14-058 at 6-7.
[16] *Id.* at 7.
[17] Order No. 84-720 (1984 WL 1022595).
[18] *Id.*

concluding that "[t]hirty-five years of avoided cost data is needed to "promote the development of a diverse array of permanently sustainable energy resources" and to" create a settled and uniform institutional climate for the qualifying facilities in Oregon."[19]

In 1991, the OPUC decided that the term of a non-standard contract should be the result of negotiation between the QF and utility, whether the contract is obtained by competitive bid or implementation of PURPA.[20] However, the Commission noted that "the further into the future [avoided cost] projections are made, the greater the risk the projections will not accurately represent actual conditions at the end of the projection period."[21] To address this risk, the Commission adopted three criteria that the utility and QF should use to determine whether a contract longer than 20 years is warranted:

1. Whether there is a high probability that the resource will be operable well beyond 20 years;
2. Whether the developer could obtain financing for the resource for contract lengths of less than 20 years; and
3. Whether the resource's physical and cost characteristics make contract terms of more than 20 years advantageous for all parties.[22]

In 1996, "as the energy industry was undergoing tremendous change and evolving towards more competitive markets[,]" the Commission approved Portland General Electric (PGE)'s request to shorten the term of PURPA

[19] *Id.*, *quoting* ORS 758.515(2)(a) and (3)(b).
[20] *Id.*
[21] *Id.*
[22] *Id.*

contracts to five years.[23] Staff supported PGE's request noting that it was difficult to justify contracts more than five years given the continued movement toward a competitive marketplace for electricity and the prevalence of wholesale transactions for terms of five years or less.[24]

In 2005, the Commission increased the term of the standard contract from five years to 20 years, but limited the fixed-price portion of the contract to 15 years.[25] The Commission noted that a 20-year term with fixed prices for 15 years balanced two goals, the need to accurately price power in the later years of the contract and to facilitate financing for a QF project: "[O]ur fundamental objective is to establish a maximum standard contract term that enables eligible QFs to obtain adequate financing but limits the divergence of standard contract rates from actual avoided costs."[26]

In 2007, the Commission ordered that QFs negotiating non-standard contracts were entitled to select a contract term of up 20 years and were not precluded from negotiating a longer term.[27]

In Phase I of the Investigation into Qualifying Facility Contracting and Pricing, the Commission declined to change the 20-year contract term or the 15-year fixed-price portion of the contract.[28]

[23] Order No. 96-21. *See also* Order No. 05-584 at 10, *citing* Order No. 96-21 (describing circumstances leading to PGE application and decision in 1996).
[24] Order No. 96-21.
[25] Order No. 05-584 at 10.
[26] *Id.* at 19.
[27] Order No. 07-360 at 11.
[28] Order No. 14-058 at 22 (noting that Commission made no changes to its policies for issues presented by the parties but not addressed in the Order) and at Appendix A (including length of contract term and length of fixed=price portion of contract in Issues List for Phase I).

OVERVIEW OF STAFF'S POSITION

Q. Please summarize Staff's position on PacifiCorp's application.

A. Staff opposes PacifiCorp's application to reduce the fixed price term for standard QF contracts from 15 years to three years, for reasons outlined below. Staff supports a reduction to the Eligibility Cap, and explores two options for implementing such a reduction.

ISSUE 1, QF CONTRACT TERM

Q. Please summarize the basis for PacifiCorp's application to reduce the QF standard contract term.

A. PacifiCorp cites the need to align QF contract length with its risk management policy, which adheres to a three-year time window. The Company states that it faces the same concerns as those addressed in 1996 when the Commission shortened QF contract length.[29] PacifiCorp quotes Staff's 1996 recommendation to limit the term of QF contracts: "[g]iven the continued movement toward a competitive marketplace for electricity and the prevalence of wholesale transactions for five years or less."[30]

Q. Does Staff agree that the concerns PacifiCorp is facing today can be compared to those the Commission addressed in 1996 when allowing PGE to reduce the fixed price contract term for QFs?

A. Yes, in part. Staff agrees that utilities today are operating in an environment of uncertainty, due to quickly changing renewable resource costs, uncertainty

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[29] Application, p. 9.
[30]Application, p.9, citing Order No. 96-21.

about compliance costs for thermal plants, and increasing customer interest in distributed generation, among other factors. However, there are fundamental differences between today's energy environment and that which existed in 1996. In April 1996, the Federal Energy Regulatory Commission issued its Final Rule in Order No. 888[31] following the passage of the Energy Policy Act of 1992. This created substantial uncertainty for electric utilities as wholesale electricity markets were restructured, transmission was subject to open access rules, and the role of vertically integrated utilities was subject to significant change. The Commission's action to shorten contract terms for QFs to five years was taken during that time, and should be informed by that context. Current circumstances afford more certainty and stability to vertically integrated utilities such as PacifiCorp compared to the situation in the mid-1990s.

Q. QFs currently have access to 20-year contract terms, with a fixed price period of 15 years. When and why did that change occur?

A. The Commission lengthened the term of standard contracts to up to 20 years, with a fixed price term of 15 years in Order No. 05-584, stating that "…our fundamental objective is to establish a maximum standard contract term that enables eligible QFs to obtain adequate financing, but limits the possible divergence of standard contract rates from actual avoided costs."[32] In 2007, the Commission decided that QFs negotiating a non-standard contract must

[31] Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities.
[32] Order No. 05-584 at 19.

have the option to enter into a contract of up to 20 years.[33] Staff's view is that the objective underlying the Commission's decision in its 2005 order has not changed, although the environment in which QFs and utilities operate has.

Q. What factors have changed since Order No. 05-584?

A. The economics of QF projects change, sometimes significantly, as capital costs of different project technologies vary, tax incentives are put into place, renewed, or allowed to expire, and avoided costs of utilities change, among other factors.

Q. Should these factors prompt a change in the fixed price term of QF contracts?

A. No. The need for QFs to have a reasonable ability to access financing still exists. To the extent the changing environment increases the risk that avoided cost prices will diverge from the utility's costs over time, this risk should not be addressed in a way that could significantly impair QFs' ability to obtain financing and inhibit QF development in Oregon. Staff found nothing in PacifiCorp's filing that would rebut the Commission's initial (and reinstated) policy regarding the QF contract term.

Q. Are there other reasons that Staff does not support the reduction in the fixed price time period?

A. Yes. Oregon avoided cost pricing is based on a resource sufficiency/ deficiency construct. This means that avoided costs are based on the market during the period in which the utility is forecast to have sufficient resources,

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[33] Order No. 07-360 at 11.

and based on the fixed and variable costs of the avoided resources (nonrenewable and renewable) after the sufficiency period ("deficiency period"). If the term of the contract is too short, the QF's ability to receive deficiency-period avoided cost prices is extremely limited. Three-year contracts, or even 10-year contracts in the current situation when new resources are not planned for that time period, would limit QFs to avoided cost prices that reflect the market only, and would not be long enough to pay any avoided costs based on the utility's next avoidable resource.

Q. Please explain why Staff believes PacifiCorp's concerns regarding the magnitude of the risk associated with the 15-year fixed term of QF contracts are overstated.

A. First, PacifiCorp has presented several statistics that do not meaningfully support the argument that its QF activity is increasing so significantly. For example, Mr. Griswold states

> The magnitude and potential impact of this increased PURPA activity is best measured by comparing the total amount of existing and proposed Oregon PURPA projects to the Company's Oregon retail load. Using 2014 as an example, the Company's average total Oregon retail load was 1,661 MW and its minimum total Oregon retail load was 1,027 MW. The 925 MW of existing and proposed PURPA contracts in Oregon at their nameplate capacity would be enough to supply 56 percent of the Company's average Oregon retail load and 90 percent of the Company's minimum Oregon retail load."[34]

A comparison of the 925 MW of capacity of existing and proposed QF contracts, to an energy measure of Oregon retail load is not useful. A 2014 load annual average of 1,661 MW (or, 1,661 aMW) relates to a peak load that

[34] PAC/100, Griswold 3 at 12-18.

is significantly higher. According to PacifiCorp's 2015 IRP, the Oregon peak (non-coincident with its total system) in 2014 was 2,598 MW.[35] This means that the 925 MW of QF capacity, if all of those projects were actually constructed, would represent less than 36 percent of Oregon peak load, not 56 percent.

Further, the Company states that the 925 MW of potential QF capacity represents 90 percent its Oregon minimum load. This may be the case numerically, out of context, but all of the potential QFs will not be operating during hours of minimum load, which are typically at night when solar plants are not generating.

Finally, the Company should not use the Mid-Columbia (Mid-C) trading hub prices as a reference point for PacifiCorp's market costs when comparing the market to the price obligations it holds for QFs. Mr. Griswold states, "The average forward price curve for Mid-C for this same ten years is $35 .27 per MWh."[36] However, PacifiCorp does not make all of its market purchases at the Mid-C trading hub, as shown in the 2015 IRP. Market purchases are planned for at Mid-C, Nevada-Oregon Border (NOB), Mona, and California-Oregon Border (COB).[37] The weighted average of purchases at these hubs is higher than those at Mid-C, so the price gap the Company cites is overstated.

[35] PacifiCorp 2015 IRP, Appendix A, *Table A.6 – Non-Coincident Jurisdictional Peak 2000 through 2014*.
[36] PAC/100, Griswold 29 at 7-9.
[37] PacifiCorp 2015 IRP,.*Table 8.7 – PacifiCorp's 2015 IRP Preferred Portfolio*, p. 196.

Q. Does Staff believe Commission action is required to address the risk identified by PacifiCorp?

A. As explained below, Staff does support a reduction to the Eligibility Cap for standard contracts and pricing. Though the Commission does not use the Eligibility Cap to manage the type of risk identified by PacifiCorp, a consequence of lowering the Eligibility Cap is that the magnitude of the potential harm associated with avoided cost prices diverging from the utility's costs is reduced.

Q. What is Staff's reasoning in not recommending more significant changes?

A. A primary driver of the economics for QF projects is the avoided cost prices paid by the PacifiCorp, which have been steadily decreasing in recent years.

Q. Please explain.

A. PacifiCorp's avoided costs have declined in recent years. Table 1 below shows PacifiCorp's recent avoided costs, their respective deficiency period start dates, and the deficiency periods identified in PacifiCorp's 2015 Integrated Resource Plan (IRP) as filed.[38]

[38] Staff cites the baseload avoided costs prices per MWh because the values for capacity are comparable.

Table 1. PacifiCorp Avoided Costs and Deficiency Periods.

	Effective August 2014:		Effective June 2015:		2016
	Avoided Cost per MWh	Deficiency Period Start	Avoided Cost per MWh	Deficiency Period Start	Post-IRP Avoided Cost Filing Deficiency Period Start
Nonrenewable Baseload	$48.40	2024	$39.31	2024	2028*
Renewable Baseload	$56.85	2024	$51.26	2024	None*
	*IRP as filed				

Q. How could the Company's 2015 IRP filing potentially impact avoided costs?

A. PacifiCorp's 2015 IRP is currently under review by the Commission. In the IRP as filed, the acquisition of PacifiCorp's next significant nonrenewable resource moves out four years, from 2024 to 2028.[39] For renewables, the preferred resource portfolio in PacifiCorp's 2015 IRP contains *no* resource acquisition during the 20-year planning period.[40] The Commission Special Public Meeting to consider PacifiCorp's IRP is scheduled for December 17, 2015. When the required post-IRP acknowledgment avoided cost filing is made, it is likely that the nonrenewable avoided cost prices will decline again, and there may not be a renewable avoided resource during the planning period.

Q. Are any other changes to PacifiCorp's avoided costs anticipated during the next year?

A. Possibly. A decision is forthcoming in Docket UM 1610 Phase II regarding the standard avoided cost price capacity payment calculation for certain QFs, which may affect each of the three investor-owned electric utilities in Oregon.

[39] PacifiCorp 2015 IRP,.*Table 8.7 – PacifiCorp's 2015 IRP Preferred Portfolio*, p. 196.
[40] Id.

Q. Please summarize Staff's position with respect to the financial risk to ratepayers resulting from QF contracts that obligate the utility to 15 years of fixed payments.

A. Staff understands that longer term contracts inherently expose ratepayers to risk that the fixed prices in the contract will be higher than the costs for power in the market and for the avoided resource during the deficiency period. Conversely, long-term fixed price contracts can result in benefits to ratepayers, in the event the opposite situation occurs. Energy prices have remained low for an extended period of time due to a combination of factors including reduced load growth during a prolonged economic downturn, the effectiveness of energy efficiency efforts, and sustained downward pressure on natural gas prices due to the abundant supply of natural gas and as new technologies are employed, among others. However, over time, the avoided cost prices should be sometimes higher and sometimes lower than the actual avoided costs of power in the later years of a QF contract. Staff believes that in the long run the risks of overestimating the fixed rates should balance out the risks of underestimating.

Additionally, solar QFs are currently in a unique situation due to two factors that may not persist at the level and rate that is currently observed: 1) prices for major components of solar projects have declined significantly in recent years; and 2) the substantial 30 percent federal Investment Tax Credit for solar projects is scheduled to drop to 10 percent at the end of 2016. These factors, in combination with the goal of ensuring QFs have reasonable access to financing, and the reduced avoided cost prices, are the basis for Staff's recommendation to retain 15-year fixed cost prices in standard QF PPAs.

Q. A significant portion of Mr. Griswold's testimony addresses PacifiCorp's risk management policy and its hedging program horizon. Should the Commission change the PURPA contract term so that it aligns with the horizon PacifiCorp employs in hedging policies?

A. No. The Commission's policies for PURPA are intended to balance the Commission's interests in QF development and ratepayer protection, as the Commission stated in its 2005 order: "[T]his Commission has consistently interpreted its PURPA mandate to be the adoption of policies and rules that promote QF development, using among other tactics accurate price signals and full information to developers, while ensuring that utilities pay no more than avoided costs."[41]

In contrast, PacifiCorp's hedging strategies are not based on this careful balance. In its testimony in this docket, PacifiCorp focuses on how limiting the fixed-price term of QF contracts may minimize risk but fails to address the other part of the equation, whether these shorter contracts will promote QF development.[42]

Q. Does the fact PacifiCorp has decided to use three-year contracts in its hedging strategy compel the Commission to reduce the term of PURPA contracts?

[41] Order No. 05-584 at 11.
[42] See PAC/100, Griswold/13-29.

A. No. Staff is not aware that Commission provides ex ante approval of utilities' program or strategies. Whether PacifiCorp's hedging strategy is reasonable is a matter resolved in a rate proceeding.[43] PacifiCorp's assertions that its hedging strategy should compel a particular Commission decision regarding PURPA contract length are not particularly compelling.

Q. PacifiCorp states that limiting the fixed price contract term to three years would better align it with the Company's IRP cycle.[44] Does Staff agree?

A. No, not when that statement is used as a justification for shortening the fixed price term. The IRP "cycle" may be 2 years, but the IRP analysis time frame is 20 years. If the IRP analysis is sufficiently robust to support a resource decision, it is sufficiently robust to forecast avoided costs 20 years (or, the current 15 year fixed price time period) into the future.

Q. Does PacifiCorp provide examples of QFs operating under shorter term contracts?

A. Yes. However, the example given is for combined heat and power (CHP) QFs. For CHP projects, electric generation is an incidental, secondary activity rather than a primary business activity. In addition, because they depend on a waste stream that can be unpredictable, their operations often vary from year to year. Standard QF contracts require an estimate of annual generation "which amount of energy PacifiCorp will include in its resource planning,"[45] as well as average

[43] See e.g., Order Nos. 11-432 and 12-437.
[44] PAC/100, Griswold/32..
[45] I PacifiCorp Power Purchase Agreement, Firm QF, 10 MW or less; Recitals.

monthly output estimates[46] For these reasons, CHP projects cannot be meaningfully compared to other types of QFs such as wind and solar, for which the annual energy output is more uniform and predictable over a longer contract term.

ISSUE 2, QF STANDARD CONTRACT ELIGIBILITY CAP

Q. What is Staff's position on PacifiCorp's application to reduce the Eligibility Cap for standard contracts?

Staff believes that the 10 MW eligibility cap as it applies to PacifiCorp is no longer accomplishing the original Commission objectives of reducing market barriers to QF development.[47] Figures 1 and 2 portray the 27 solar QF projects with executed standard contracts with PacifiCorp.[48] Figure 1 shows the number of projects by developer[49] (developers with less than three projects are grouped as "Other Solar), and the total MW for each. Figure 2 shows total MW, and the median project size for each entity. Multiple 10 MW standard contracts have been executed with individual entities. In one case, a single entity has contracted for seven 10 MW solar projects and one 8 MW project. Often, developers enter into multiple contracts on the same day: One developer executed five contracts for 36.7 MW of solar on the same day in May 2015, and another two contracts for 19.9 MW one month later. A second

[46] PacifiCorp Power Purchase Agreement, Firm QF, 10 MW lr Less; Exhibit D-1.
[47] Order No. 05-584, p. 16-17; Order No. 91-1605, p. 2.
[48] PacifiCorp response to CREA data request 1.1, supplement 1. There are currently no solar QFs greater than 10 MW under contract with PacifiCorp in Oregon.

developer executed eight contracts for 78 MW of solar projects within one week in June 2015.

Figure 1. 2014-15 (partial) Solar MW and Number of Projects by Developer

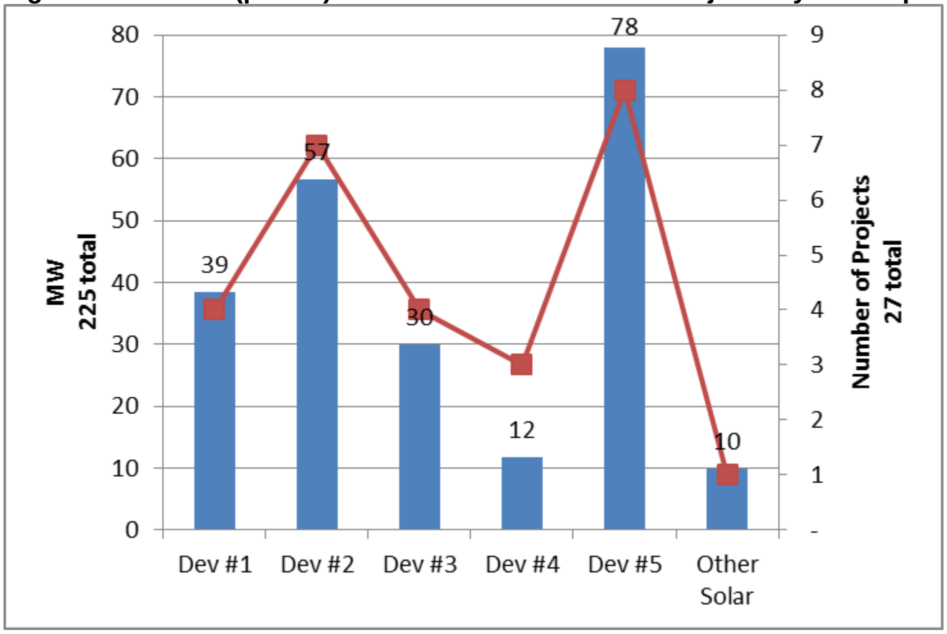
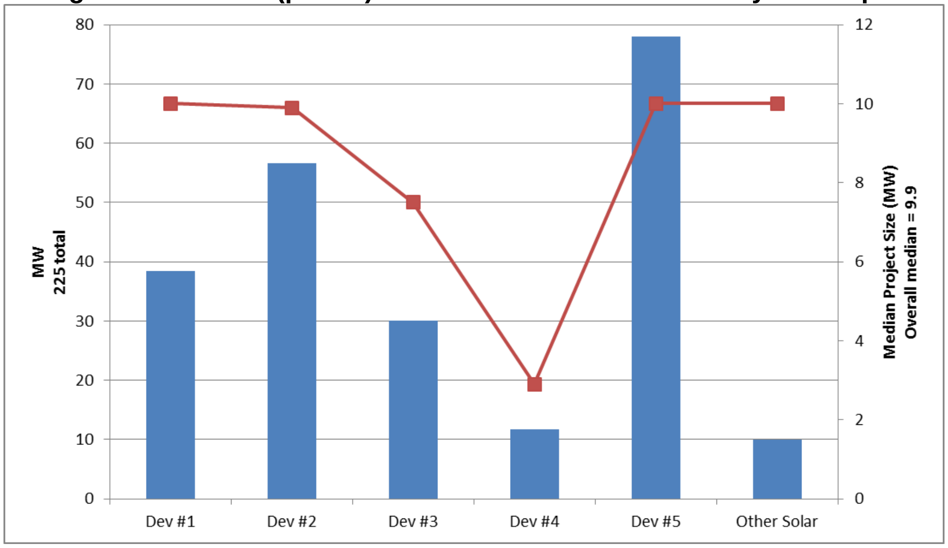


Figure 2. 2014-15 (partial) Solar MW Total and Median by Developer



Q. What conclusions does Staff reach based on this data regarding the current 10 MW eligibility cap?

A. Based on the number and median sizes of projects initiated by different developers, and the execution dates of the contracts, Staff concludes that some solar developers are initiating multiple projects that are at or near the Eligibility Cap so that they qualify for standard QF contracts and pricing. If the capacity for these projects were combined, the developers would fall into the category of QFs that do not have the protection of the Eligibility Cap. As shown in Figure 1 above, multiple developers have three or more QF contracts, including one with eight contracts for a total of 78 MW. Staff does not think that this was what the Commission established with an eligibility cap of 10 MW. Entities such as those described above have the ability to overcome the market barriers the Commission's policy is intended to mitigate.

Q. Given this conclusion, what Eligibility Cap does Staff recommend for wind and solar projects?

A. Given the recent pattern of development, and the potential harm to ratepayers of long-term fixed price agreements, Staff concludes that a lower Eligibility Cap is needed. Staff recommends an Eligibility Cap of two to four MW as a range that takes into consideration the capacity of typical individual wind turbines. This Eligibility Cap would limit the possibility of gaming the Commission policy with multiple projects when taking into account the mitigating effect of the five-mile radius requirement, and it would protect small QF developers from the above-mentioned market barriers.

Q. With an Eligibility Cap of between two and four MW, won't developers simply break their projects into smaller projects in order to qualify for standard contracts and prices?

A. Possibly. It is correct to say that the nature of solar and wind projects is that they can be relatively easily divided into multiple projects as long as they can meet criteria for disaggregation t. [50] This is not the case for other projects such as geothermal and hydro. The five-mile requirement effectively inhibits disaggregation of these projects. Interconnection, land acquisition, permitting and other infrastructure costs would be increased using this approach, if projects must disaggregate into multiple small projects, but perhaps not significantly enough to remove it. However, as stated above, given the current avoided cost environment, Staff believes that the two- to four-MW level is a reasonable way to reduce risk while continuing to allow for relatively large solar QF projects.

Q. Are there other factors that should be taken into account when considering changes to the fixed price contract term and the Eligibility Cap?

Yes. Although an Oregon Clean Power Plan (CPP) compliance framework has not been developed by the State, Oregon Department of Environmental Quality nor the Public Utility Commission, it is fair to consider a role for qualifying facilities in any CPP compliance strategy. Under either a rate- or mass-based compliance regime, QFs will provide compliance instruments. These

[50] Order No. 06-586, Appendix B, Exhibit A.

instruments will be valuable to the QF developer and to those needing compliance instruments. If markets are developed under a state or multi-state CPP compliance effort, it is important that participation in these markets be reasonably diverse. It is therefore important that potential barriers to QF development be carefully considered, as they may hamper the development of QFs which may be part of this state's compliance tool box.

This proposed Eligibility Cap is intended to support the objectives of 1) moving large developers proposing multiple projects at the same time toward negotiated agreements, and 2) continuing to provide opportunities to develop significant renewable energy projects in Oregon.

Q. What options would remain for QFs larger than Staff's proposed eligibility cap, if this recommendation is adopted?

A. QFs above the standard contract eligibility cap have the option of negotiating a contract with the utility under Schedule 38. This option mitigates a large share of the risk of fixed price contracts based on a standard avoided resource because the specific operating characteristics of the QF, and the resulting system impacts, are incorporated into the avoided cost price.

Q. Does PacifiCorp currently have any executed negotiated contracts with Oregon QFs?

A. Yes, the Company has three negotiated QF contracts; two of the projects are larger than 10 MW, and one is lower.[51] None are for wind or solar QFs.

[51] PacifiCorp response to CREA data request 1.1, supplement 1.

Q. If a QF owner believes that PacifiCorp is not negotiating in good faith, are there avenues for resolving the situation?

A. Yes, the Commission has implemented a dispute resolution process for disputes arising during negotiation of a non-standard PURPA contract.[52]

Q. Does this conclude your testimony?

A. Yes.

[52] Order No. 07-360.

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WITNESS: BRITTANY ANDRUS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualifications Statement

October 15, 2015

WITNESS QUALIFICATIONS STATEMENT

NAME:	Brittany Andrus
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst Energy Resources and Planning Division
ADDRESS:	201 High Street SE Suite 100 Salem, Oregon, 97301-3612
EDUCATION:	M.B.A. Portland State University, Portland, Oregon B.A. English Michigan State University, East Lansing, Michigan
EXPERIENCE:	I have been employed at the Oregon Public Utility Commission since 2011. My current responsibilities include research, analysis and technical support for electric company proceedings, with an emphasis on resource planning, power costs, and qualifying facilities under PURPA. I was previously employed for 17 years by the Bonneville Power Administration, a wholesale power marketing agency within the federal Department of Energy. My duties included energy efficiency planning and program management, long term load and revenue forecasting, long term power sales contracts, rate impact analysis, short term load forecasting, power and transmission scheduling, and management of load forecasting data and processes.