- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

In the Matter of the Application of Rocky Mountain Power for Approval of Changes to Renewable Avoided Cost Methodology for Qualifying Facilities Projects Larger than Three Megawatts	)))))))	DOCKET NO. 12-035-100 ORDER ON PHASE II ISSUES

ISSUED: August 16, 2013

SHORT TITLE

PacifiCorp Large Renewable QF Avoided Costs

SYNOPSIS

The Commission approves an avoided cost method to determine indicative prices for power purchases from certain QF projects larger than three megawatts. Further, the Commission determines: (1) RECs shall be retained by QFs, unless provided for otherwise by a negotiated contract; and (2) the Proxy/PDDRR method is approved for determining avoided costs for all small power production QFs.

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INTRODUCTION

This matter is before the Public Service Commission of Utah ("Commission") on the October 9, 2012, application ("Application") of PacifiCorp, dba Rocky Mountain Power ("PacifiCorp" or "Company") for consideration of proposed changes to the current method for calculating avoided cost pricing for large wind qualifying facilities ("QFs") served through Electric Service Schedule No. 38, Qualifying Facility Procedures ("Schedule 38"), among other things. The current method was approved by the Commission October 31, 2005,[1] ("2005 Order") and reaffirmed September 20, 2012[2] ("Blue Mountain Order"). PacifiCorp's application includes a motion to stay ("Motion") that portion of the 2005 Order establishing the Market Proxy method for determining indicative pricing for large wind QFs (i.e., in excess of three megawatts of generating capacity) up to the target level of wind resources in PacifiCorp's Integrated Resource Plan ("IRP").

As determined in the 2005 Order and reaffirmed in the Blue Mountain Order, the Partial Displacement Differential Revenue Requirement or "PDDRR" method for determining avoided energy cost along with the "Proxy" method for determining avoided capacity cost constitute the Commission's established method (referred to hereafter as the "Proxy/PDDRR method") for determining indicative avoided cost pricing for non-wind resources and, under certain conditions, wind resources.[3]

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[1] *See In the Matter of the Application of PacifiCorp for Approval of an IRP-based Avoided Cost Methodology for QF Projects Larger than One Megawatt,* Docket No. 03-035-14 (Report and Order; October 31, 2005).

[2] *See In the Matter of Blue Mountain Power Partners, LLC's Request that the Public Service Commission of Utah Require PacifiCorp to Provide the Approved Price for Wind Power for the Blue Mountain Project,* Docket No. 12-2557-01(Order on Request for Agency Action; September 20, 2012).

[3] *See* supra n.1, pp.6-7.

The 2005 Order also sets forth the method for determining avoided cost pricing for wind resources, referred to as the "market price proxy" or "Market Proxy" method, which is based on the winning bid in PacifiCorp's most recently executed request for proposal ("RFP") for a wind resource.[4] The 2005 Order directs PacifiCorp to apply the Market Proxy method to provide indicative avoided cost pricing to wind QFs up to the target level for wind resources in the IRP. When the target level is achieved, the applicable method becomes the Proxy/PDDRR method.

In this proceeding, PacifiCorp requests examination of whether the Market Proxy method continues to produce avoided costs for wind QFs that are in the public interest, particularly with respect to the following areas: (1) the definition of the IRP target, (2) the timing of the need for renewable resources, and (3) the treatment of resources to be acquired for renewable portfolio standard ("RPS") compliance. Additionally, PacifiCorp requests examination of the Proxy/PDDRR method for renewable QF resources in connection with: (a) the capacity contribution of intermittent resources, (b) the type of resource deferred, i.e., thermal or renewable, and (c) integration costs.

Finally, PacifiCorp seeks examination of the ownership of renewable energy credits ("RECs") from QF resources. This includes an evaluation of: (1) the ownership of RECs under the Proxy/PDDRR method, and (2) the right of a QF to buy-back RECs and the associated price.

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[4] The current Market Proxy price for wind resources was determined in the 2009R RFP in which PacifiCorp selected the Dunlap I wind facility located in Wyoming.

PROCEDURAL HISTORY

On November 8, 2012, the Commission held a duly-noticed scheduling conference and thereafter issued a scheduling order on November 13, 2012, bifurcating the proceeding into two phases. Phase I of the proceeding addressed PacifiCorp's Motion and allowed parties to file direct, rebuttal, and surrebuttal written testimony in advance of the December 12, 2012, evidentiary hearing. On December 20, 2012, the Commission issued an order denying the Motion and reaffirming the Commission's intention to re-examine the current avoided cost pricing method for large wind QFs in Phase II of the proceeding.[5]

The Utah Division of Public Utilities ("Division") and Utah Office of Consumer Services ("Office") actively participated in each phase of this proceeding. Additionally, the following parties intervened in this proceeding: Blue Mountain Power Partners, LLC; Ellis-Hall Consultants, LLC; Energy of Utah, LLC ("Energy of Utah"); EverPower Wind Holdings Company; Kennecott Utah Copper, LLC and Tesoro Corporation ("KUC/Tesoro"); Renewable Energy Advisors ("REA"); Scatec Solar North America, Inc. ("Scatec"); SunEdison, LLC ("SunEdison"); Utah Clean Energy ("UCE"); Utah Office of Energy Development; Wasatch Wind Intermountain, LLC; and Western Resource Advocates ("WRA").

PacifiCorp filed direct testimony for Phase II on January 31, 2013, with direct testimony filed by the Division, Office, UCE, KUC/Tesoro, Scatec, Energy of Utah, and REA on March 29, 2013. On May 15, 2013, PacifiCorp, Division, Office, UCE, and KUC/Tesoro filed rebuttal testimony, and SunEdison filed comments in response to direct testimony. PacifiCorp, Division, Office, UCE, KUC/Tesoro, Scatec, Energy of Utah and REA filed surrebuttal

[5] The procedural history in this docket up to December 20, 2012 is set forth in the Commission's order of the same date.

testimony on May 30, 2013. The Commission convened a duly-noticed hearing to examine Phase II issues on June 6, 2013. Post-hearing briefs were filed by PacifiCorp, Division, Office, Scatec, UCE, SunEdison and KUC/Tesoro on June 27, 2013.

The following interested parties provided written comments on the issues addressed in Phase II: Department of Army, Army Energy Initiatives Task Force; Naomi Franklin; iMatter Utah; Interwest Energy Alliance; Ben Mates; Park City; Renewable Energy Businesses; RenewableTech Ventures; Salt Lake City Corporation, Mayor Ralph Becker; Utah Chapter of the Citizens Climate Lobby; and Ian Wade. In addition to written comments, the following interested parties provided oral comments or testimony at the Public Witness Day hearing held on June 13, 2013: Ben Mates, Mark Thomas, Kelly Stowell, Sara Ma, Tyler Poulson, Greg Shepard, Bridget Stuchly, Christopher Thomas, Nia Sherar, Bill Barron, Lieutenant Colonel Matt Price, Bryan Harris, Hans Ehrbar, and Alan Naumann.

REGULATORY FRAMEWORK

In the 2005 Order and Blue Mountain Order we discussed at some length the Public Utility Regulatory Policies Act of 1978 ("PURPA") and the rules promulgated thereunder by the Federal Energy Regulatory Commission ("FERC") requiring electric utilities to purchase energy and capacity from QFs at the utility's avoided cost. While PURPA expressly directed FERC to prescribe regulations governing rates paid by electric utilities to QFs, it gave individual states the responsibility to implement FERC's regulations regarding such rates.[6]

Those regulations (along with FERC's decisions) set forth the principles that guide the Commission's decision. Tracking the statutory language of PURPA, FERC's

[6] *See* 16 U.S.C. 824a-3(f); accord, *FERC v. Mississippi*, 456 U.S. 742, 751 (1982).

regulations provide that QF rates must "be just and reasonable to the electric consumer of the electric utility" and "not discriminate against qualifying cogeneration and small power production facilities," and that "nothing in [FERC's regulations] requires any electric utility to pay more than the avoided costs for purchases."[7] FERC's regulations further define avoided costs as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."[8]

Beyond the generic description of avoided costs provided above, FERC's regulations, at 18 C.F.R. § 292.304(e), require individual states to take into account the following factors, to the extent practicable:

> (1) The data provided pursuant to § 292.302(b), (c), or (d), including State review of any such data;[9]
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> (2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:
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>> (i) The ability of the utility to dispatch the qualifying facility;
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>> (ii) The expected or demonstrated reliability of the qualifying facility;
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>> (iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;
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>> (iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;
>>
>> (v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

[7] 18 C.F.R. § 292.304(a)(1)-(2).
[8] 18 C.F.R. § 292.101(b)(6).
[9] 18 C.F.R. § 292.302 requires electric utilities to provide system cost data.

> (vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and
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> (vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and
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> (3) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2) of this section, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and
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> (4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

Consideration of the factors listed above illustrates that the determination of avoided costs is dependent on multiple assumptions, data inputs, calculations and estimates. The Commission relies on the robust participation of numerous parties to thoroughly test and vet such data and assumptions to produce evidence to which the guiding principles discussed above are applied. Further, FERC has provided states wide latitude in implementing FERC’s regulations so long as implementation does not run contrary to FERC’s regulations.[10] With these guiding principles in mind, our decisions herein seek to achieve an avoided cost methodology consistent with PURPA, FERC’s regulations and the policy goals of the State of Utah.

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[10] *See, e.g.*, *American REF-FUEL Company of Hempstead*, 47 FERC ¶61,161 at 61,533 (1989) (“States are allowed a wide degree of latitude in establishing an implementation plan for section 210 of PURPA, as long as such plans our consistent with our regulations. Similarly, with regard to review and enforcement of avoided cost determinations under such implementation plans, we have said that our role is generally limited to ensuring that the plans are consistent with section 210 of PURPA. . . .”)

DISCUSSION, FINDINGS AND CONCLUSIONS

I. Ownership of Renewable Energy Credits

A. Parties' Positions

PacifiCorp and the Office contend the utilities required to purchase electric power from QFs should own RECs and that any value associated with RECs should be credited to ratepayers. PacifiCorp asserts its position is grounded in good public policy. It reasons RECs are the essence of the requirement under PURPA for utilities to purchase QF power; therefore, RECs are part of what the utility is buying with the payment of avoided costs. PacifiCorp notes that if it "does not get the RECs, it is not receiving the very characteristic that enabled the facility to achieve its QF status."[11] PacifiCorp further maintains "PURPA contains no requirement that a purchasing utility pay twice for what it has already bought."[12]

In support of its position, PacifiCorp points to recent decisions from neighboring state public utility commissions determining RECs are owned by the purchasing utility (Wyoming) or divided equally between the utility and QF (Idaho). PacifiCorp also points to California's policy of allowing utilities to keep RECs from QF purchases to apply towards meeting California's RPS. In essence, PacifiCorp argues that because these state commissions believe it is good policy for RECs (or at least 50% of RECs) to go to the utility purchasing the QF power, this Commission should adopt the same policy.

Like PacifiCorp, the Office contends that because producing renewable energy is what qualifies a power producer as a QF, it follows that RECs should be tied to the flow of QF energy. The Office further submits ratepayers should own RECs generated by QFs because QFs

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[11] Clements Direct Testimony (January 31, 2013) at p. 2, lines 24-31.
[12] *Id.* at p. 4, lines 81-82.

are free to sell power to any willing purchaser, whereas ratepayers are forced to pay for a QF's power under PURPA.

Other parties addressing this issue (Division,[13] KUC/Tesoro, Scatec, UCE, Park City and Salt Lake City) assert QFs should retain RECs. Specifically, the Division and UCE argue the conveyance of RECs to purchasing utilities effectively would discriminate among different types of QFs in violation of section 201(b) 2 of PURPA, due to the disparity in value between RECs associated with renewable versus cogeneration facilities. In other words, the potential differential value of RECs that would go to a purchasing utility could result in higher avoided costs paid to certain types of QFs in violation of PURPA.

The Division, KUC/Tesoro, Scatec and UCE provide testimony supporting the following general propositions: (1) RECs are a creation of state policy objectives and under Utah law may be separated or "unbundled" from energy produced by QFs; (2) PURPA provides for the pricing of QF power (energy and capacity) at the purchasing utility's avoided cost, which does not include the value of RECs; (3) because the concept of RECs was not in existence at the time PURPA was enacted, the question of REC ownership is not addressed by PURPA but rather is a matter of policy left to individual states; and (4) Commission precedent dictates that RECs remain with the QF unless otherwise specified by contract.

B. Findings and Conclusions

We agree with the general propositions put forth by the Division, KUC/Tesoro, Scatec and UCE. First, it is undisputed that RECs are a creation of the Utah Legislature under UCA § 54-17-603. From UCA § 54-17-601(11) it is also clear that QF electricity may be

[13] The Division concludes that RECs should remain with the QF *unless* the purchase price compensates the QF for environmental attributes.

unbundled from RECs.[14] Second, we find no basis in PURPA, FERC regulations or applicable precedent that the price paid for QF power at a utility's avoided cost includes the value of RECs or any other renewable attribute. In fact, FERC has specifically concluded that "avoided cost rates are not intended to compensate the QF for more than capacity and energy."[15] Consistent with PURPA, our approved avoided cost methods compensate QFs for energy and capacity only. Thus, the Commission disagrees with PacifiCorp's contention that RECs "are part of what the utility is buying with the payment of avoided costs," and that if "the Company were to pay a QF separately for the RECs, then, the Company and its customers would be paying twice for RECs." Third, it is undisputed that REC ownership is not addressed by PURPA but rather is a policy matter reserved for individual states.

With these foundational principles established, we turn to our prior decision that RECs are a distinct commodity with value that may be severed from the power generated by a QF and remain with a QF unless otherwise specified by contract. *See*, *In the Matter of the Complaint of Cottonwood Hydro, LLC v. Rocky Mountain Power* Docket No. 10-035-15, (Report and Order; May 27, 2010). PacifiCorp asserts "this is the first time the Commission is being asked to make a policy decision on this issue in the absence of an existing contract. The Commission has not determined who owns a REC when it is created."[16] Based on a perceived

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[14] UCA § 54-17-601(11) defines an unbundled renewable energy certificate as "a renewable energy certificate associated with qualifying electricity that is acquired by an electrical corporation or other person by trade, purchase, or other transfer without acquiring the electricity for which the certificate was issued …."

[15] *American Ref-Fuel Co.*, 107 FERC ¶ 61,016 at P 15. *See also*, *Morgantown Energy Associates*, 139 FERC ¶ 61,066 at P. 47 (2012).

[16] PacifiCorp Post-Hearing Brief at p. 12.

lack of clarity in *Cottonwood Hydro*, PacifiCorp argues: "RECs created from the energy the Company is obligated to purchase from QFs cannot be claimed to be owned by anyone."[17]

To clarify our holding in *Cottonwood Hydro*, unless provided for otherwise in a negotiated contract, RECs are retained by the QF and may be sold and valued separately from the energy produced by the QF. In other words, once created, RECs do not remain in some type of ownership limbo until such ownership is specified by contract. Rather, consistent with existing statutes and our previous orders, we affirm RECs are retained by the QF unless the QF and purchasing utility have agreed by negotiated contract to an alternate REC ownership structure.

Our decision is consistent with prior Commission orders and state policy. As set forth in UCA § 54-12-1(2):

> It is the policy of this state to encourage the development of independent and qualifying power production and cogeneration facilities, to promote a diverse array of economical and permanently sustainable energy resources in an environmentally acceptable manner, and to conserve our finite and expensive energy resources and to provide for their most efficient and economic utilization.

Allowing renewable energy developers to retain RECs is consistent with state policy set forth in UCA § 54-12-1(2) and will help encourage renewable and qualifying facility development.[18]

In addition, other Utah statutes addressing REC ownership evidence the state's policy to encourage renewable and qualifying facility development. For example, UCA § 54-17-603(4) states in relevant part that a REC may be issued for "qualifying electricity" and the

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[17] *Id*.

[18] Utah's state policy is also consistent with one of the key purposes of PURPA—to encourage the development of cogeneration and renewable energy facilities in the United States. *See FERC v. Mississippi*, 456 U.S. 742, 750 (1982).

activities of an "energy user" described in UCA § 54-17-601(e). Subsection 54-17-601(10)(e) (i)-(vi) provides a list of such activities including:

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> (ii) a solar thermal system that reduces the consumption of fossil fuels, with the quantity of renewable energy certificates to which the user is entitled determined by the equivalent kilowatt-hours saved, except to the extent the commission determined otherwise with respect to net-metered energy;
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> (iii) a solar photovoltaic system that reduces the consumption of fossil fuels with the quantity of renewable energy certificates to which the user is entitled determined by the total production of the system, except to the extent the commission determines otherwise with respect to net-metered energy;
>
> (iv) a hydroelectric or geothermal facility with the quantity of renewable energy certificates to which the user is entitled determined by the total production of the system, except to the extent the commission determines otherwise with respect to net-metered energy;
>
> (v) a waste gas or waste heat capture or recovery system, other than from a combined cycle combustion turbine that does not use waste gas or waste heat, with the quantity of renewable energy certificates to which the user is entitled determined by the total production of the system, except to the extent the commission determines otherwise with respect to net-metered energy; . . .

Significantly, each of the previously listed activities includes express language entitling the producer of renewable energy, i.e., the "energy user" to a quantity of RECs based on the total production of the facility. This statute expresses the state's policy to encourage or incent the development of renewable energy by providing RECs to parties willing to make such investments and engage in activities that produce renewable energy. Moreover, there is no evidence in the record suggesting that a policy granting RECs to utilities purchasing QF power would encourage renewable resource development. To the contrary, the evidence shows retention of RECs by the QF is critical for encouraging renewable resource development.[19] In summary, our decision to allow renewable energy developers to retain RECs is consistent with state policy, applicable precedent, and the evidence in this case.

II. Market Proxy Method

A. Parties' Positions

1. Overview

PacifiCorp, Division, Office and KUC/Tesoro assert the Market Proxy method no longer produces reasonable avoided costs and should be discontinued because the method is linked to a dated IRP renewable resource target that no longer aligns with recent IRPs. The Division and Office also generally agree with PacifiCorp's argument that the Market Proxy method fails to account for circumstances in which IRP wind resources are not cost-effective but rather are acquired solely for RPS compliance requirements. PacifiCorp argues no party provided evidence to justify continued use of the Market Proxy method.

PacifiCorp further explains that although the Market Proxy method made sense when the 2005 Order was issued and PacifiCorp was regularly conducting requests for proposals ("RFPs") for renewable resources, this is no longer the case. At hearing, PacifiCorp testified the 2013 IRP identifies the next deferrable wind plant acquisition occurring in 2024; whereas the Market Proxy method assumes the next deferrable wind plant timing is the same as the first year of a renewable QF contract. As such, the Market Proxy method provides wind QF pricing based on the results from PacifiCorp's most recent wind RFP, i.e., the 2009R RFP, as if PacifiCorp is

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[19] *See* Resta Direct Testimony at p.2, lines 14-18.

actively acquiring renewable resources now or in the near future. PacifiCorp argues this resource timing mismatch fails to yield reasonable avoided cost payments.

PacifiCorp recommends using the Proxy/PDDRR method approved by the Commission in the 2005 Order as the basis for producing avoided costs for all renewable resources, including wind resources. PacifiCorp further recommends, however, that the Proxy/PDDR method should be updated to account for more current information regarding the capacity contribution of renewable resources and the cost of integrating intermittent generation.

The Division argues the Market Proxy method provides reasonable results only when the operating characteristics of the proxy plant closely match those of the QF, the QF exactly replaces the entire capacity and energy of the proxy plant, and the QF does not significantly affect other plant additions or system operations. The Division does not believe these conditions are being or can be met. The Division asserts the Market Proxy method is therefore flawed and should be discontinued permanently.

UCE, Energy of Utah, Scatec and SunEdison assert that although modifications may be needed, the Market Proxy method should not be discontinued. UCE and SunEdison argue that when renewable resources are selected as least-cost, least-risk resources in the IRP preferred portfolio over the entire planning horizon, the Market Proxy method is still a reasonable approach for calculating avoided costs for renewable QFs. UCE disagrees with the Division, arguing the Market Proxy method provides the closest match for resource cost avoided.

UCE further contends PacifiCorp's proposed Proxy/PDDRR method does not reflect true capacity values and avoidable costs. According to UCE, the Proxy/PDDRR method should only be used when the Commission determines there are no cost-effective renewable resources in a thoroughly vetted IRP. Alternatively, UCE maintains if the Proxy/PDDRR method is used, it should be modified to account for the appropriate capacity values of renewable resources and for the risk mitigating effects such resources have on fuel price volatility and environmental compliance costs.

As summarized above, PacifiCorp identifies three areas of concern regarding whether the Market Proxy method continues to produce avoided costs that are in the public interest: (1) defining what constitutes the targeted amount of acquired renewable resources in the IRP, (2) the timing and need for renewable resources, and (3) the treatment of resources acquired for RPS compliance. We now review parties' positions in greater detail in each of these three areas.

2. Definition of IRP Target

PacifiCorp, Division and Office contend a wind resource must be cost-effective to be included within the IRP target. These parties assert PacifiCorp has met its wind acquisition target and claim wind resources identified in the 2011 IRP Update are planned only to comply with RPS requirements outside Utah and are not cost-effective. The Office agrees with PacifiCorp's assertion that the mere inclusion of RPS wind resources in the IRP does not justify the continued use of the Market Proxy method.

UCE contends that as long as renewable resources are selected in the IRP, the IRP target remains the cumulative amount of renewable resources called for over the planning horizon. Additionally, UCE maintains, after a thorough review of costs and risks, the IRP should determine whether renewable resources are added only for compliance purposes or are found to be in the public interest for other reasons. Consequently, UCE states the IRP acknowledgement process may need to be adjusted to facilitate use of the Market Proxy method.

Scatec asserts PacifiCorp's 2011 IRP Update contains no target for large scale solar resources and argues solar resource costs are now comparable to wind. Scatec recommends PacifiCorp include a 200 to 300 megawatt system target for solar resources.

SunEdison notes PacifiCorp's 2013 IRP selects solar resources in some cases and argues it is possible that such resources could be included in a least-cost, least-risk IRP portfolio. According to SunEdison, this demonstrates why a change from the Market Proxy method to the Proxy/PDDRR method may be premature.

3. Timing and Need for Renewable Resources

PacifiCorp argues that unlike the Proxy/PDDRR method, the Market Proxy method does not account for the timing of new resource additions in the IRP. According to PacifiCorp, it is important to consider the timing of new resource additions in order to ensure QF prices do not exceed the costs PacifiCorp can avoid. PacifiCorp asserts the Market Proxy method is designed to reflect the market cost to PacifiCorp if it were to competitively procure a new resource today. PacifiCorp argues customers are not indifferent if they pay the full cost of such a resource that is not needed until several years in the future. PacifiCorp also argues that because the 2011 IRP Update contains only uneconomic wind resources acquired in the future solely for RPS compliance and has no currently avoidable cost-effective wind resources, there is a mismatch between future need and current wind QF pricing under the Market Proxy method.

Similarly, the Office contends PacifiCorp is not actively pursuing wind resources and as a result, the prices derived under the Market Proxy method are four years out of date. The Office asserts wind contract prices have varied substantially since the 2005 Order approved the Market Proxy method. Likewise, fuel prices and REC markets have varied significantly along with PacifiCorp's load forecast and resource expansion plans since that time. According to the Office, unlike the Market Proxy method, the Proxy/PDDRR method is designed to reflect such changes in avoided costs and is therefore superior.

To make the Market Proxy method workable going forward, UCE recommends PacifiCorp account for the timing and need for new wind resource additions using a current IRP and determine the market proxy cost on the basis of renewable resource cost assumptions corresponding to the IRP's preferred portfolio. As an alternative approach, UCE proposes basing avoided cost pricing assumptions either on: (1) revenue streams received for Company-owned wind projects; (2) the average cost of PacifiCorp's wind power purchase agreements ("PPAs"); or (3) capacity-weighted averages of wind PPAs from publically available contracts from other western utilities. UCE argues this approach could also be used for geothermal, solar or biomass resources.

Scatec contends since the Market Proxy method is tied to wind resources, potential large-scale solar QFs are prevented from receiving the treatment wind QFs currently receive under the method. As a result, Scatec recommends PacifiCorp modify the Market Proxy method to provide avoided cost pricing specific to solar resources.

4. Resources Acquired for RPS Compliance

Both PacifiCorp and the Office contend the existence of required RPS resources in the IRP does not justify continued use of the Market Proxy method. PacifiCorp argues the Market Proxy method does not account for circumstances where IRP wind resources are not cost-effective and are present in the plan solely for the purpose of complying with any RPS outside of Utah. If system allocated resources were assumed to be used to meet any RPS, PacifiCorp argues additional renewable resources that are not cost-effective would be required.

Moreover, if PacifiCorp were to procure a renewable QF contract today, PacifiCorp argues the full output from that facility could not be used to fulfill another states' RPS. Since Utah QFs cannot offset the needed volume of renewable resources that are acquired solely for RPS compliance, PacifiCorp contends such resources should not be the basis for setting Utah avoided costs, as they would be under the Market Proxy method.

The Office argues there are significant differences in the nature of wind resources included in PacifiCorp's IRP in 2005 and those included in the 2013 IRP solely to meet RPS compliance in other states. The Office agrees with PacifiCorp's assertion that the mere inclusion of RPS wind resources in the IRP for such purposes does not justify the continued use of the Market Proxy method.

B. Findings and Conclusions

In the 2005 Order we determined the Market Proxy method is appropriate for providing indicative pricing for wind QF generation, assuming PacifiCorp is acquiring cost effective wind resources through RFPs to meet load requirements during the next 20 years, as identified in its IRP. The last competitively bid system-wide RFP for a renewable resource was conducted in 2009. Because PacifiCorp is not actively conducting any system-wide RFPs for wind resources, the last executed wind contract from an RFP (i.e., the 2009R RFP) upon which Market Proxy indicative pricing is currently based, runs the risk of becoming out of date. We therefore discontinue use of the Market Proxy method for determining indicative prices for Schedule 38 wind QFs going forward and expand the application of the Proxy/PDDRR method to include wind QFs seeking indicative pricing. This action will ensure our method for determining indicative prices will continue to reflect changing avoided costs in light of changing conditions present in PacifiCorp's ongoing IRPs.

We are persuaded PacifiCorp's proposed Proxy/PDDRR method, with certain adjustments discussed below is a reasonable method for determining wind resource indicative prices going forward. Therefore, future requests for indicative pricing for wind QFs under Schedule 38 will be calculated using the Proxy/PDDRR method as has been the case for other QFs previously. This approach will ensure future indicative prices, and therefore QF energy and capacity payments will reflect appropriately the costs reasonably expected to be avoided or deferred over the term of the contract.[20]

III. Proxy/PDDRR Method Applied to Renewable QF Resources

With the decision to discontinue use of the Market Proxy method for indicative wind QF prices and to instead use the Proxy/PDDRR method for all QFs, we next turn to issues raised by PacifiCorp and other parties concerning the application of this method to renewable QFs under Schedule 38.

[20] With our decision regarding the discontinued use of the Market Proxy method, the Company's request to examine the right of a QF to buy-back RECs under the Market Proxy method is moot going forward.

A. Type of Resource Deferred and Treatment of RPS Required Resources

1. Parties' Positions

PacifiCorp asserts that in the 2005 Order the Commission approved use of the next deferrable thermal resource as the proxy in the Proxy/PDDRR method as it applies to wind resources when the IRP target of cost-effective wind resources has been achieved. At hearing, PacifiCorp stated wind resources could be used as the proxy for capacity payments when cost-effective wind resources are planned to be acquired and indicated it has done so in other states. PacifiCorp further stated this approach does not require capacity contribution adjustments to the renewable QF resource.

UCE contends that if the Commission finds the IRP includes cost-effective renewable energy resources after a thorough review of costs and risks, avoided cost rates for renewable energy QFs should be based on the "proxy" costs of corresponding renewable energy resources. UCE argues it is unnecessary to base the avoided cost rate specifically on the most recent RFP for that renewable energy source. Rather, the rate must be based on the costs of the same type of resource. The Office also supports use of a "like" resource as the deferrable resource for capacity payments when cost-effective renewable resources are in PacifiCorp's IRP. The Office argues the source of the proxy capacity payments should be the IRP data for renewable resources, the same as is currently done for deferrable thermal resources.

The Office also argues it is reasonable for PacifiCorp to exclude future RPS wind resources shown in the current IRP from the PDDRR study when it computes avoided costs. According to the Office, these resources are not part of the Utah least cost plan and may never be built, and the ultimate allocation of their associated costs and benefits is presently undecided.

The Division notes avoided energy costs are different when resources required for RPS compliance only are excluded from PacifiCorp's production cost study. The Division further recommends the Commission open a separate docket with technical conferences to determine the proper treatment of non-cost-effective resources for compliance with RPS requirements.

2. Findings and Conclusions

The record supports a distinction in the application of the Proxy/PDDRR method to renewable QF resources depending on whether the planned resources reflected in PacifiCorp's IRP include cost-effective renewable resources. We concur with PacifiCorp, Office and UCE that when PacifiCorp's planned resources include cost-effective renewable resources, "like" resource costs are reasonable to use as the proxy for purposes of avoided cost calculations of QF capacity payments. We therefore approve this change in the application of the Proxy/PDDRR method to renewable QF resources seeking indicative pricing under Schedule 38. For example, thermal QF capacity payments will be based on the capital costs of the next deferrable thermal resource and renewable QF capacity payments will be based on the capital costs of the next like deferrable renewable resource so long as such a cost-effective renewable resource is present in PacifiCorp's planned resources. Under these conditions, no adjustment to capacity payments is necessary as discussed below.

When a like cost-effective renewable resource is not included in PacifiCorp's planned resources, the capital cost of the next deferrable thermal resource will serve as the proxy for the Schedule 38 QF capacity payment. For wind and solar QFs, adjustments shall be made to capacity payments to account for the intermittent capacity contribution of these resources as discussed below.

Finally, all renewable resources included in the IRP planned resources which are not cost-effective but are required to meet a state's RPS will be treated as system resources in the calculation of QF energy payments. We find this approach is consistent with the 2010 Protocol on inter-jurisdictional cost allocation approved in Docket No. 02-035-04.[21]

B. Capacity Contribution of Intermittent Renewable Resources

1. Parties' Positions

a. Exceedance Method

According to PacifiCorp, capacity contribution represents the percentage of a generator's nameplate capacity PacifiCorp can reliably use to satisfy the system peak load requirement. To measure the historical capacity contribution of renewable resources, PacifiCorp introduces an approach referred to as an Exceedance Method which it developed and presents for the Commission's consideration in this docket. The Exceedance Method measures the level of intermittent capacity necessary to provide the same level of reliability in the system peak hour as expected from the next deferrable resource in the IRP, a Combined Cycle Combustion Turbine ("CCCT") in this case. Because the full output of a CCCT is expected to be available in more than 90 percent of peak load hours, the Exceedance Method measures the level of power achieved or exceeded by PacifiCorp's intermittent resources in 90 percent of the top 100 summer peak load hours each year.

PacifiCorp testifies the capacity contribution values described below are used in the IRP to select resources based on their ability to meet system peak load in a least-cost, least-risk manner. Further, PacifiCorp explains the capacity payment in the Proxy/PDDRR method

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[21] *See In the Matter of the Application of PacifiCorp for an Investigation of Inter-Jurisdictional Issues*, Docket No. 02-035-04, (Report and Order; February 3, 2012).

accounts for partially deferring resources selected in the IRP. Therefore, PacifiCorp argues the capacity contribution value used in the Proxy/PDDRR method should be the same value used in the IRP for consistency and to ensure the capacity payment to renewable QFs is valid.

i. Wind Resources

To calculate wind resource capacity contribution, PacifiCorp identifies the top 100 summer peak load hours in each year between 2007 and 2011 and aligns the aggregate capacity factor from both PacifiCorp's owned and non-owned wind resources occurring with the corresponding load hour. Between 2007 and 2011, PacifiCorp represents its portfolio of wind resources provides an average capacity contribution of 4.1 percent of nameplate capacity in more than 90 percent of the 100 peak load hours.

ii. Solar Resources

PacifiCorp states it has limited historical solar data from which it can develop the capacity contribution value of a class of geographically distributed solar resources on its system. Consequently, PacifiCorp testifies it uses the average solar energy production data developed by the National Renewable Energy Laboratory ("NREL") from five locations within PacifiCorp's service territory (Pocatello, Idaho; Yakima, Washington; Pendleton, Oregon; Lander, Wyoming; and Salt Lake City, Utah) to determine the capacity contribution value.

PacifiCorp compared the simulated hourly solar data to the top 100 summer load hours in each year during the period 2007 through 2011 using the Exceedance Method. PacifiCorp claims, unlike wind resources where levels of generation change each year depending on the output of the resource set, simulated solar output remains constant in each year and is compared to changes in the timing of the top 100 peak summer load hours from year-to-year.

In its solar resource analysis, PacifiCorp differentiates between classes of solar resources based on whether the solar resource is configured to maximize energy output ("Fixed Solar") or whether it is configured to maximize output during peak load periods, i.e., solar aligned more towards the West or with a tracking device ("Tracking Solar"). The analysis is performed twice: first, with all of the resources configured to simulate Fixed Solar, and second, with all of the resources configured to simulate Tracking Solar. PacifiCorp's Exceedance Method yields recommended capacity values of 11.5 percent for Fixed Solar and 25.9 percent for Tracking Solar.

b. Criticisms of Exceedance Method

The Division, Office, UCE, SunEdison, and Scatec are critical of the Exceedance Method. The Office claims the Exceedance Method is overly simplistic and cannot measure the reliability benefits of renewable QFs. The Office argues reliability needs impact PacifiCorp's reserve margin requirements which, in turn, may drive the need for new capacity resources. From a reliability perspective, the Office argues it is not the average availability or the availability of a resource in 90 percent of the top 100 load hours that matters, but rather the availability of a resource in all hours and particularly during extreme conditions that matters the most.

The Division asserts the Exceedance Method sets arbitrary thresholds and is incongruous with PacifiCorp's IRP studies. The Division further contends that while the IRP may use system peaks to determine the timing of additional resources, all hours of the year are evaluated to consider the type of resources needed. Thus, similar to the Office's argument, the Division contends the value of a resource in the context of PacifiCorp's choice of a least-cost, least-risk IRP preferred portfolio is based on the resource's contribution in all hours of the year, as opposed to the top 100 load hours in a given study period.

The Division, SunEdison and UCE criticize PacifiCorp's use of the Exceedance Method for solar resources because the method compares simulated hourly NREL solar profile data to PacifiCorp's actual 100 high load hours. Additionally, SunEdison criticizes PacifiCorp's method because it fails to assign value to renewable resources that provide capacity beyond the 100 high load hours.

Scatec and SunEdison argue PacifiCorp's use of simulated solar data from five locations within Company territory (Pocatello, Idaho; Yakima, Washington; Pendleton, Oregon; Lander, Wyoming; and Salt Lake City, Utah) is unrealistic based on the location of likely Schedule 38 solar facilities in southern Utah. At hearing, PacifiCorp stated the five locations selected by PacifiCorp for its study are not consistent with the location of large-scale solar projects planned for development.

PacifiCorp does not dispute the assertion that renewable resources provide capacity value beyond the 100 hours utilized by the Exceedance Method and acknowledges the Exceedance Method is a new capacity valuation approach used solely by PacifiCorp. At hearing, PacifiCorp stated that comparing a five-year, five-state average simulated solar production data to actual load data could result in a possible mismatch but indicated that due to a lack of actual solar data, PacifiCorp was forced to rely on the average solar production data.

c. Support for a Capacity Factor Allocation Method

The Division, Office, SunEdison and UCE contend the Effective Load Carrying Capability ("ELCC") and the Equivalent Conventional Power ("ECP") capacity calculation methods put forward by NREL, and contained in UCE Exhibit 4.1 (D) ("NREL Study"), are more appropriate methods to calculate capacity values for renewable resources. These parties argue both methods, characterized as reliability-based, seek to capture the reliability value of the renewable resources through use of a Loss of Load Probability ("LOLP") or Loss of Load Expectation ("LOLE") modeling approach.[22]

Although it supports a reliability-based method such as the ELCC method for calculating (wind) capacities, the Division states alternative methods which approximate the ELCC and ECP approaches, as put forward in the NREL Study, may be warranted because the ELCC and ECP approaches are data-intensive and difficult to execute. For example, the Division further testifies the LOLP calculation requires considerable data including the distribution of the loads and resource availability. Moreover, to calculate the LOLE, the LOLP for each hour must be calculated.

While the Office argues the NREL Study results are not Company-specific and are of limited value for determining renewable resource capacity values in this proceeding, the Office does not believe the methods underlying the NREL Study are inappropriate. The Office recommends the Commission require PacifiCorp to implement a capacity value based on one of the reliability methods documented in the NREL Study or in the IEEE study attached as exhibit DPU 2.1 to the Division's rebuttal testimony.

In light of the complexity of the ELCC and ECP methods, the Division, the Office and UCE support use of the Capacity Factor Allocation Methodology ("CF") also described in the NREL Study. They testify the CF method is a much simpler method that reasonably

[22] The NREL Study defines LOLP as the "probability of a loss of load event in which the system load is greater than available generating capacity during a given time period."

approximates the results achieved by the ELCC method for calculating capacity values for renewable QFs. These parties argue the CF method is a reasonable alternative approach due to its simplicity and its relative accuracy. The CF method is a capacity value approximation technique that considers the renewable resource's output in each hour of a study period. According to the Division, it also considers the resource's capacity factor during periods in which the system faces a high risk of an outage event.

The Division claims that in addition to being reasonably accurate and simple to execute, the CF method has two other distinct advantages relative to the ELCC and ECP methods analyzed in the NREL Study: (1) it is transparent because - once the LOLP for each hour is calculated, the remaining calculations are relatively easy to follow and understand; and (2) it yields reasonably accurate results using a limited amount of data.

Both the Division and UCE reference the NREL Study conclusion which states that using as few as the top 10 percent of load hours in the capacity calculation may be sufficient for an effective CF analysis. To that end, UCE recommends a CF analysis be performed using PacifiCorp's top 10 percent load hours rather than the highest 100 load hours per year. Where the data may not be available, such as for solar resources, the Division recommends the use of the CF method described in the NREL Study, which shows the top 10 hours is sufficient for valid solar capacity contribution results.

As noted by the Division, PacifiCorp did not calculate wind capacity contribution using the ELCC or CF methods as requested in a Division data request. The Division states that in addition to the ELCC value, PacifiCorp's response would have provided the data necessary to calculate capacity values using the CF method. Since it lacks the data, the Division states the

Commission will need to determine a capacity value for renewable wind resources at least on an interim basis.

In order to identify an interim value, the Division calculates wind resource capacity values using a variation of PacifiCorp's Exceedance Method where the top 100 load hours in each year between the period 2007 and 2011 are aligned with actual hourly generation output from both PacifiCorp's owned and non-owned wind resources occurring with the corresponding load hour. The difference in the Division's approach is that it applies higher weights to the lowest wind output values, as these values are more representative of expected wind output.

Using this weighting approach, the Division employs the Exceedance Method to determine wind capacity values occurring at the 90th percentile of the weighted values. Under the "weighted" Exceedance Method approach, the Division calculates a wind capacity value of 8.72 percent. Applying a simple average to this entire data set, the Division estimates a wind capacity value of 12.03 percent.

The Division performs two additional iterations using its approach by halving the weights occurring above both the mean and median wind capacity values, resulting in wind capacity values of 10.51 percent, and 10.12 percent, respectively. Thus, the Division proposes a wind capacity contribution in the range of 8.72 percent to 12.03 percent on an interim basis. The Division further recommends the Commission convene technical conferences and collect party comments to resolve the issue of wind resource capacity values.

The Division does not calculate an interim solar capacity value. The Division states the NREL Study includes specific estimates for the Salt Lake City area based on the CF method which ranges from 68 percent for Fixed Solar to 84 percent for Tracking Solar. The Division maintains these values could be used on an interim basis.

The Office contends a simple version of the CF method without use of LOLP is referenced in the NREL Study and can be used to estimate renewable resource capacity values. The Office calculates a wind capacity value by averaging the capacity factors of wind resources in PacifiCorp's east control area during the highest 500 summer hours over PacifiCorp's five year period. This yields a result of 20.5 percent. Similarly, the Office averages PacifiCorp's simulated solar resource data results over the same period and calculates capacity contribution values of 49.6 percent for Fixed Solar and 59.1 percent for Tracking Solar.

Like the Division, the Office notes the data necessary to calculate values using the LOLP weighting methods were not provided. The Office argues, however, that its solar capacity value estimates would be a reasonable set of values to use for this proceeding, and the 20.5 percent wind capacity value is a more reasonable alternative than PacifiCorp's result. The Office believes these estimates could be used on an interim basis, but a better study using the NREL methods should be performed with results made available to parties for review and comment. In terms of the impact on overall wind avoided costs, according to the Office, it makes little difference which method is used as the resource sufficiency period does not end until 2024.

d. Company's Criticism of CF Method

PacifiCorp contends a renewable QF should be paid for the amount of capacity it can defer at the time of system peak. PacifiCorp argues the methods proposed by parties (the ELCC and CF methods) are energy-based measures, and none of the other studies introduced by

NREL and proposed by the other parties addresses the issue of how much of a capacity payment should be provided to a QF.

PacifiCorp asserts the Commission should not use the capacity contribution numbers that come directly from the NREL Study. PacifiCorp states the NREL Study warns against using the values in their study at an individual utility level since they were based on WECC-wide load and resource data rather than individual utility load data. The Office concurs with PacifiCorp regarding the limited usefulness of the NREL Study data.

PacifiCorp also argues basing capacity values on the ELCC and CF methods would have the effect of reducing the reliability of the system to meet system peak load. PacifiCorp asserts system reliability would be significantly affected if these methods were adopted, and it would be inappropriate to inflate payments to renewable QFs when the result would be a reduction in system reliability. The only alternative in such a situation, according to PacifiCorp, would be to add additional resources to bring reliability levels back up to targets listed in the IRP with the result being that customers effectively pay twice for the same capacity.

2. Findings and Conclusions

PacifiCorp's Exceedance Method is not an industry standard approach. Rather, it was developed by PacifiCorp, and this is our first exposure to this method. The record shows this method arbitrarily weights Company data because it fails to consider reliability measures, like LOLP, in the determination of the hours evaluated.[23] Therefore, the method may incorrectly state the reliability value of an intermittent resource and the capacity payment to intermittent QFs, and contravene the important objective of ratepayer indifference. Given the evidence

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[23] *See* UCE Exhibit 4.1(D), p. 2.

demonstrating significant flaws in the Exceedance Method and the fact it results in a wind capacity contribution assumption for reliability planning and QF capacity payments substantially different from values used or approved in the past, we reject its use in this case.

We are persuaded by the parties opposing PacifiCorp's method that the ELCC and CF methods described in the NREL Study reasonably account for LOLP. Therefore, we direct PacifiCorp to calculate capacity contribution for wind and solar resources for the Proxy/PDDRR method using either the ELCC method or CF method considering LOLP.

In this proceeding, however, no party provides a capacity contribution study for wind or solar resources using the ELCC method or CF method considering LOLP and Company data. Accordingly, we adopt the Office's estimation of a 20.5 percent capacity payment for wind QFs, pending PacifiCorp's filing of an ELCC or CF method study. We accept the Office's recommendation because it is a simple average, rather than an arbitrary weighting, of historical wind resource capacity factors in PacifiCorp's eastern control area. Since all Utah QFs will be located in PacifiCorp's eastern control area, we find this is a reasonable value for Utah wind QF capacity payments. This decision is also similar to our prior ruling,[24] and, therefore, maintains a consistent value pending further review of the ELCC or CF study results. Moreover, it is partially corroborated by the Division's analysis.

Similarly, pending PacifiCorp's filing of the ELCC or CF study results for solar resource capacity contribution, we accept the Division's recommendation for capacity payments to Fixed and Tracking Solar QFs of 68 percent and 84 percent, respectively. These are the values derived using the CF method cited by the Division in the NREL Study based on WECC

[24] *See* Docket No. 03-035-14, pp. 22-23.

load and resource data and Salt Lake City solar data. We recognize PacifiCorp's loads and resources may produce different outcomes but accept the results in the NREL Study as a reasonable interim proxy representing a gradual change from our prior ruling on solar QFs which did not address capacity payments for solar resources under the Proxy/PDDRR method.

C. Wind Integration Cost

1. Parties' Positions

To account for wind integration costs, PacifiCorp proposes using its 2012 Wind Integration Study ("WIS"), as included in the 2013 IRP. In the WIS, PacifiCorp calculates wind integration cost to be $4.35 per megawatt hour, on a levelized basis over a 20 year period beginning in 2013.

No party opposes PacifiCorp's proposed wind integration costs as contained in the WIS. The Office states that while the WIS has not been approved by the Commission nor has it yet been endorsed by the Technical Review Committee ("TRC") guiding its development, it is the most practical alternative available at this time. The Office recommends implementing the proposed $4.35 wind integration charge. Once the WIS has been fully vetted by the TRC and the Commission in the IRP process or a future general rate case, the Office recommends the Commission consider applying any necessary changes to the wind integration value based on the comments.

2. Findings and Conclusions

Based on the general consensus among the parties to rely on the 2012 WIS, we find that for the present, the $4.35 per megawatt hour wind integration charge is reasonable for calculating Schedule 38 avoided energy costs for wind QF resources.

D. Solar Integration Cost

1. Parties' Positions

PacifiCorp indicates it has not calculated integration costs for solar resources and proposes using wind integration costs as a proxy for the cost of integrating solar resources. PacifiCorp contends this approach is reasonable because solar resources are intermittent and require integration support during higher cost, peak load hours. At hearing, PacifiCorp testified the timing of solar is not aligned with the timing and changes of loads; therefore, PacifiCorp incurs additional ramping requirements from dispatchable resources.

PacifiCorp does not agree with assertions that solar energy is less variable and more predictable than wind energy, and therefore rejects arguments that solar integration costs should be lower than wind integration costs. On the contrary, PacifiCorp argues solar resources have the potential to exhibit sharp output swings due to rapidly changing cloud cover. PacifiCorp argues these swings can occur instantaneously, thereby straining the system, increasing ramping reserves requirements and requiring reserves to be held during peak hours when the opportunity costs of holding such reserves is highest. Further, because solar resources are intermittent, PacifiCorp argues it is not reasonable to exclude integration costs from solar resource avoided cost calculations.

The Division and Office contend PacifiCorp does not provide sufficient analytical support to justify using wind integration costs as a reasonable proxy for solar resources. The Division testifies that relative to wind, solar incidence at given locations is more predictable and argues PacifiCorp should be better able to deal with the daily fluctuations in solar generation. Without a definitive study demonstrating that solar and wind integration costs are equal, the

Division believes it is unreasonable to assume solar integration costs are equivalent to wind integration costs. The Division contends it is also unreasonable to assert there should be no solar integration costs; the variability in solar generation due to cloud cover and the daily need to ramp up and ramp down other resources in response demonstrates solar integration costs are warranted.

The Division performed a coefficient of variation analysis using historical load data for wind, peak-oriented solar, and energy-oriented solar facilities and concludes Fixed Solar resources are approximately 65 percent as variable as wind, while Tracking Solar is about 50 percent as variable as wind. The Division therefore proposes that Fixed Solar resources be charged an integration cost of 65 percent of the current $4.35 per megawatt hour wind integration cost, or approximately $2.83 per megawatt hour and 50 percent of the $4.35 per megawatt hour or $2.18 per megawatt hour for Tracking Solar. The Division recommends these proposed solar integration costs as interim measures until such time as PacifiCorp provides a definitive solar integration cost study or until another party provides better estimates.

The Office accepts the Division's proposal to use 50 and 65 percent of the wind integration cost as interim solar integration costs and recommends the Commission require PacifiCorp to perform a solar integration study and update the avoided costs when results become available and that study has been vetted.

UCE also supports a solar integration study utilizing a technical review committee and indicates such a study could provide information to evaluate whether solar generation incurs integration costs for PacifiCorp. According to UCE, until PacifiCorp performs such a study and actually quantifies solar integration costs, solar QFs should not be charged integration costs.

Scatec supports a solar integration study but believes it would be detrimental to its project in Utah to apply solar integration costs today. Scatec states there will be a cost with integration but that it is currently unknown.

2. Findings and Conclusions

The record before us suggests there is no conclusive evidence showing wind and solar projects impose the same integration costs. We are persuaded by the Division's testimony that solar resources appear to be relatively less variable and more predictable than wind resources. The evidence before us also demonstrates the variability in solar generation output requires PacifiCorp to responsively dispatch other resources thereby demonstrating the reasonableness of implementing a solar integration charge of some amount. Given the absence of a solar integration study, we accept the Division's proposal to respectively apply 65 percent and 50 percent of the wind integration cost in PacifiCorp's 2012 WIS to Fixed Solar and Tracking Solar resources. We therefore direct PacifiCorp to apply a solar integration charge of $2.83 per megawatt hour for Fixed Solar resources and a $2.18 per megawatt hour solar integration cost for Tracking Solar resources. These values will remain in effect pending PacifiCorp filing a solar integration study.

E. Capacity Payment – Sufficiency Period

1. Parties' Positions

UCE and SunEdison contend renewable QF avoided cost pricing should include a capacity payment in the initial year of a QF's operation since a renewable QF contributes capacity value in each year of the QF contract. UCE contends PacifiCorp is heavily reliant on the market to meet its resource needs both during periods of resource sufficiency and deficiency. In effect, according to UCE, PacifiCorp is in a constant period of resource deficiency.

SunEdison argues renewable resources such as solar can offset blocks of market purchases which are unused or sold back into the market at prices lower than the purchase price. In addition, UCE contends the capacity value provided by a renewable QF helps PacifiCorp meet its planning reserve margin in every year of the contract. Therefore QFs should be paid for their capacity contribution in their initial year of operation beyond the value of avoided front office transactions. Further, the payment should be based on avoiding the capital costs of a CCCT.

PacifiCorp and the Office disagree with UCE's proposal that QFs should receive a capacity credit during times of resource sufficiency. According to PacifiCorp, UCE's approach does not reflect costs PacifiCorp can avoid. PacifiCorp contends the Proxy/PDDRR method provides QFs a capacity value for the deferral of FOTs for each year prior to the year of the next deferrable CCCT. In its "without QF" production costs study using its Generation and Regulation Initiative Decision ("GRID") model, according to the Office, PacifiCorp includes additional FOTs, which, in turn, include a cost for capacity provided, thereby appropriately reflecting associated capacity costs in the avoided cost calculation.

2. Findings and Conclusions

We are persuaded the Proxy/PDDRR method properly reflects avoided capacity costs associated with FOTs during the period of resource sufficiency. The evidence proffered by PacifiCorp and the Office shows a QF's displacement of FOTs, as determined within the GRID model, results in what PacifiCorp would have otherwise paid for capacity purchases. Thus, the inclusion of additional capacity value when a FOT is displaced would over-compensate the QF and violate the ratepayer neutrality objective.

F. Energy Payment – Deficiency Period

1. Parties' Positions

UCE recommends renewable QFs receive an "un-capped" energy payment stream in the resource deficiency period. REA and UCE argue the Proxy/PDDRR method undervalues the energy value provided by QFs. UCE indicates the GRID model accurately calculates the avoided energy costs which result when the renewable QF displaces its assigned portion of the deferrable resource. Once the deferrable resource comes online, however, UCE contends PacifiCorp adjusts the energy payment outside of the GRID model by capping the entire energy payment at the dispatch cost of the next deferrable resource at PacifiCorp's assumed fuel price.

UCE contends if a QF provides energy during periods when PacifiCorp is making market purchases it is likely that the QF will be avoiding such purchases, as opposed to operating Company-owned gas plants. Hence, consistent with arguments made by REA and SunEdison, UCE contends if the GRID model results show the QF is displacing higher cost resources, the QF should be compensated accordingly.

The Office disagrees with UCE, and PacifiCorp and the Division state no adjustment is made to cap the energy payment stream at the assumed fuel price of the avoided CCCT. At hearing, PacifiCorp clarified it does not cap energy prices for firm QF contracts and argues it only caps energy prices for unscheduled and nondispatchable power.

2. Findings and Conclusions

Based on the testimony of PacifiCorp and Division, we find PacifiCorp does not cap energy payments to wind and solar QFs for firm power. This finding is consistent with our 2005 Order which requires capping the energy payments for QFs which provide unscheduled power. We therefore decline to adopt UCE's and REA's recommendation on this issue.

G. Hedging and Environmental Values of Renewable Resources

1. Parties' Positions

UCE, Scatec, SunEdison and Energy of Utah contend increased Company reliance on natural gas resource and market purchases exposes ratepayers to fuel price volatility and environmental compliance cost risk. These parties argue QFs provide PacifiCorp and ratepayers a cost-effective means to mitigate these risks by diversifying the resource mix through fixed price power purchases of renewable power, allowing PacifiCorp to avoid significant up-front investments. UCE argues hedging and environmental cost projections are no less known and measurable than fuel price forecasts which PacifiCorp regularly uses in computing avoided energy costs. Avoided cost payments to renewable QFs, according to these parties, should therefore reflect the avoided costs PacifiCorp would likely incur in the absence of the risk mitigating benefits renewable QFs would otherwise provide.

UCE recommends an adder of $9.31 per megawatt hour to account for the avoided cost of incurring carbon regulation compliance costs and argues this value should be adopted if the Commission determines that RECs belong to the utility purchasing the QF power without additional compensation to the QF for the REC value. SunEdison also contends solar resources provide a long-term insurance policy against fuel price volatility and environmental policy impacts. SunEdison suggests using NYMEX prices over a 25-year period as an approach to value such risk. Otherwise, these parties do not recommend a specific value or adder to account for avoided hedging or environmental costs.

PacifiCorp, the Division and Office oppose recommendations put forward by UCE, Energy of Utah, and Scatec Solar to adjust the Proxy/PDDRR method for risks avoided by renewable QFs. PacifiCorp and the Office contend fuel cost or climate change risks are not known and measurable costs PacifiCorp can avoid, and adjusting the method for such would result in prices above avoided costs in violation of PURPA. PacifiCorp testifies including additional costs for such risks will unnecessarily shift costs from renewable QFs to retail customers. Until something is more definitively known about these risks, PacifiCorp recommends excluding them from avoided cost calculations. Further, PacifiCorp indicates it makes no such adjustment to reflect the risk characteristics of current non-renewable QFs, and argues avoided cost prices represent expected or median outcomes where upside and downside fuel cost risk is symmetrical. PacifiCorp argues no party proposes a specific proposal to estimate such risk.

The Division contends the Commission has no basis on which to determine the level of such costs to include in a QF payment since no party quantified or proposed a method to quantify these costs. Further, the Division contends the development of the IRP preferred portfolio, to some extent, includes the benefits of risk mitigation, as realized in varying assumptions about gas, coal, and carbon dioxide prices and environmental compliance costs, and thus compensates the QF accordingly. Likewise, the Division argues RECs also value environmental benefits, and a long-term QF contract provides price volatility mitigation regardless of the QF's fuel source.

The Division claims including such costs as an addition to the QF payment would result in double-counting and argues these values, if applied, should be determined elsewhere, such as in the development of the IRP or in another venue.

2. Findings and Conclusions

Parties in this proceeding have argued at some length as to whether PURPA allows for the inclusion of costs associated with hedging fuel and power costs, fuel price volatility, environmental compliance, potential carbon regulation, and climate change as part of the avoided cost payment for renewable QFs. Specifically, parties take divergent positions regarding the meaning of FERC's guidance that a "state may not set avoided cost rates or otherwise adjust the bids of potential suppliers by imposing environmental adders or subtractors that are not based on real costs that would be incurred by utilities." *Southern California Edison*, 71 F.E.R.C. ¶ 61, 269, 62,080 (June 2, 1995).

The Office argues *Southern California Edison* makes it abundantly clear that avoided cost rates may only account for costs which actually would be incurred by utilities; therefore, costs which are speculative, or otherwise not measureable or quantifiable are inappropriate in arriving at avoided cost.

In response, UCE's post-hearing brief cites a more recent FERC decision which, according to UCE, provides clarification on appropriate costs to include in avoided cost rates. *Cal. Pub. Utility Comm'n*., 132 FERC ¶ 61, 047 (July 15, 2010), *clarification granted & rehearing denied*, 134 FERC ¶ 61, 059 (October 21, 2010), *rehearing denied*, 134 FERC ¶

61,044 (Jan. 20, 2011). In that case, FERC addressed the California Public Utilities Commission's ("CPUC") setting of offer prices for purchases from combined heat and power ("CHP") facilities from electric utilities. The price included a 10 percent bonus if the CHP facility was in a transmission or distribution constrained area, to reflect the avoided costs of the system upgrades.

The CPUC's pricing, according to FERC, did not necessarily run afoul of PURPA if certain requirements were met. In addition, FERC offered the following clarifying guidance:

> The Commission has previously found that an avoided cost rate may not include a 'bonus' or 'adder' above the calculated full avoided cost of the purchasing utility, to provide compensation for, for example, environmental externalities above avoided costs. But, if the environmental costs 'are real costs that would be incurred by utilities,' then they 'may be accounted for in a determination of avoided cost rates.' <u>Accordingly, if the CPUC bases the avoided cost 'adder' or 'bonus' on an actual determination of the expected costs of upgrades to the distribution or transmission system that the QFs will permit the purchasing utility to avoid, such an 'adder' or 'bonus' would constitute an actual avoided cost determination and would be consistent with PURPA and our regulations</u>. *Id.* at 61,267-68. (emphasis added)

Based on this language, UCE concludes that "not only is it conceptually consistent with PURPA to account for time (long-term vs. short-term costs) in avoided costs, but it is also consistent with PURPA to include costs that *are not specifically associated with the energy or capacity* of avoided resource(s)."[25] UCE then draws a comparison between transmission and distribution system upgrades avoided by QF purchases (which are not specific energy or capacity components of the resource avoided) and "costs uniquely attendant to fossil fuel use" that are "not necessarily specific energy and capacity components of alternative

[25] UCE Post-Hearing Brief at p.3.

generation resources, but are nevertheless relevant to a determination of costs that are avoided by purchasing electricity from renewable QFs."[26]

We do not dispute the conclusion from the CPUC case that avoided costs based on an actual determination of the expected costs of upgrades to the distribution or transmission system would be consistent with PURPA. We have a difficult time, however, drawing a correlation between avoided distribution and transmission costs that may be projected and tested with a reasonable degree of certainty (*e.g.*, through transmission studies) and environmental risk factors (*e.g*. costs associated with adapting to changing climate) based upon divergent and speculative projections.

Rather, to the extent potential costs associated with environmental risks and hedging can be projected and factored into Company decision making, they should be accounted for in PacifiCorp's IRP modeling and resource portfolio evaluation process where cost, risk and uncertainty are evaluated to identify a least-cost, risk-adjusted, long-term resource plan.[27]

Preparation and review of PacifiCorp's IRP action plan is governed by UCA § 57-17-301, UAC R746-430 and the Commission's order issued in Docket No. 90-2035-01 approving the standards and guidelines for integrated resource planning for PacifiCorp ("IRP Guidelines"). The IRP process outlined in the IRP Guidelines provides a reasonable opportunity to evaluate cost, risk and uncertainty in order to identify a least-cost, risk-adjusted, long-term capacity expansion plan. The IRP process requires the consideration of the environmental risks and fuel price volatility identified by parties in this proceeding. Moreover, the IRP Guidelines at

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[26] *Id.* at pp. 3-4.
[27] For example, the Company's 2013 IRP indicates that "[f]inal preferred portfolio selection considers additional criteria such as risk-adjusted portfolio cost, CO^2 emissions, supply reliability, resource diversity, and attainability of DSM program and renewable portfolio standard (RPS) requirements." 2013 IRP, Volume I at p. 157.

Section 7 of Attachment A state, "Avoided Cost should be determined in a manner consistent with the Company's Integrated Resource Plan."

Finally, as pointed out by FERC in the CPUC decision cited above, "a state may separately provide additional compensation for environmental externalities, outside the confines of, and, in addition to the PURPA avoided cost rate, through the creation of renewable energy credits."[28] We believe our policy with respect to REC ownership encourages renewable development without running afoul of the avoided cost principles outlined in PURPA. Thus, for the foregoing reasons, we approve no specific adjustments to value fuel price hedging, fuel price volatility or environmental risk.

IV. Process Issues

A. Queue Management

Scatec claims the current rules governing PacifiCorp's management of the QF queue are ambiguous, lack transparency, and provide PacifiCorp an unreasonable amount of discretion that can be applied in a discriminatory manner. Although the Commission takes no position regarding this assertion, Schedule 38 provides a process for resolving disputes of this nature.

B. Informational Requirements

KUC/Tesoro recommends PacifiCorp include certain information when it provides indicative pricing in response to a request from a QF. This information will enable QFs to evaluate more fully the assumptions, inputs and methodology used to determine the price paid

[28] *Southern California Edison* FERC ¶ 61, 269, 62,080 (June 1995).

for QF power. The Commission acknowledges PacifiCorp's pledge to timely provide the requested information.

ORDER

Pursuant to our discussion, findings and conclusions, we order:

1. RECs shall be retained by the QF unless the QF and purchasing utility have agreed by negotiated contract to an alternate REC ownership structure.
2. Future requests for indicative pricing for wind QFs under Schedule 38 shall be calculated using the Proxy/PDDRR method.
3. When PacifiCorp's IRP planned resources include a cost-effective renewable resource of the same type as the QF, avoided cost capacity payments under Schedule 38 shall be based on the capital costs of the next deferrable resource of the same type in PacifiCorp's IRP planned resources.
4. When PacifiCorp's IRP planned resources do not include a cost-effective renewable resource of the same type as the QF, avoided cost capacity payments under Schedule 38 shall be based on the capital costs of the next deferrable thermal resource in PacifiCorp's IRP planned resources.
5. All renewable resources included in PacifiCorp's IRP planned resources which are not cost-effective but are required to meet a state's RPS shall be treated as system resources in the calculation of QF energy payments.
6. PacifiCorp is directed to perform and file a study calculating capacity contribution for wind and solar resources for the Proxy/PDDRR method using either the ELCC method or CF method considering LOLP.

7. When PacifiCorp's IRP planned resources do not include a cost-effective wind resource and pending PacifiCorp's filing of the results of its ELCC or CF study for wind resources, PacifiCorp shall apply a 20.5 percent capacity contribution for wind QFs for the purpose of determining Schedule 38 capacity payments.
8. When PacifiCorp's IRP planned resources do not include a cost-effective solar resource and pending PacifiCorp's filing of the results of the ELCC or CF study, PacifiCorp shall apply a 68 percent capacity contribution for Fixed Solar QFs and an 84 percent capacity contribution for Tracking Solar QFs for the purpose of determining Schedule 38 capacity payments.
9. A $4.35 per megawatt hour wind integration charge shall be used for calculating Schedule 38 indicative prices for wind QF resources.
10. PacifiCorp is directed to apply a $2.83 per megawatt hour solar integration charge for Fixed Solar QF resources and a $2.18 per megawatt hour solar integration charge for Tracking Solar QF resources. These solar integration charges shall be in effect until PacifiCorp files a solar integration study.

DATED at Salt Lake City, Utah, this 16th day of August, 2013.

/s/ Ron Allen, Chairman

/s/ David R. Clark, Commissioner

/s/ Thad LeVar, Commissioner

Attest:

/s/ Gary L. Widerburg
Commission Secretary
D#246340

Notice of Opportunity for Agency Review or Rehearing

Pursuant to Utah Code Ann. §§ 63G-4-301 and 54-7-15, a party may seek agency review or rehearing of this order by filing a request for review or rehearing with the Commission within 30 days after the issuance of the order. Responses to a request for agency review or rehearing must be filed within 15 days of the filing of the request for review or rehearing. If the Commission fails to grant a request for review or rehearing within 20 days after the filing of a request for review or rehearing, it is deemed denied. Judicial review of the Commission's final agency action may be obtained by filing a Petition for Review with the Utah Supreme Court within 30 days after final agency action. Any Petition for Review must comply with the requirements of Utah Code Ann. §§ 63G-4-401, 63G-4-403, and the Utah Rules of Appellate Procedure.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 16th day of August, 2013, a true and correct copy of the foregoing was served upon the following as indicated below:

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