Sophie Hayes (12546)
Utah Clean Energy
1014 2nd Ave.
Salt Lake City, UT 84103
801-363-4046
Attorney for Utah Clean Energy

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Approval of changes to Renewable Avoided Costs Methodology for Qualifying Facilities Projects Larger than Three Megawatts	**DOCKET NO. 12-035-100** **Utah Clean Energy – Post-Hearing Brief**

INTRODUCTION

The Public Utility Regulatory Policy Act ("PURPA") was passed in 1978 in part to conserve and reduce the use of fossil fuels. FERC v. Mississippi, 456 U.S. 741, 750-51 (1980). Section 210 of Title II of PURPA (16 U.S.C. § 824a) was enacted to encourage the development of electricity generation from cogeneration and small power production facilities, specifically by sidestepping monopoly utilities' reluctance to purchase electricity from independent energy producers and overcoming regulatory obstacles for independent producers. 456 U.S. 741, 750-51 (1980). In this docket, pursuant to the requirements of PURPA, the Commission must encourage independent energy development by carving open a market in an otherwise closed monopoly system[1] and establish just and reasonable "avoided cost" rates on behalf of utility ratepayers. The proper way to accomplish this dual requirement is to fully value costs renewable QFs enable the utility to avoid over the duration of renewable QF power purchase contracts, as described below.

[1] "We are not, after all, dealing with completely free enterprise. We are, rather, dealing with the twilight world of regulated monopolies." Armco Advanced Materials Corp. v. Penn. Pub. Utility Comm'n, 634 A.2d 207, 209 (Pa. 1993).

ARGUMENT

I. IN ORDER TO MAINTAIN RATEPAYER INDIFFERENCE, THE COMMISSION MUST CONSIDER LONGER TERM COSTS AND RISKS ASSOCIATED WITH FOSSIL FUEL USE AND ACCOUNT FOR THEM IN ITS DETERMINATION OF AVOIDED COST PRICING.

A. Avoided costs can include "real costs that would be incurred by utilities" that are not necessarily energy or capacity costs.

Traditionally, avoided costs rates are based on the costs of alternative (avoided) energy and capacity, without regard to any other costs associated with alternative electricity procurement. *See* Am. Ref-Fuel Co., 105 FERC ¶ 61004, 61007 (Oct. 1, 2003). One caveat in setting avoided costs rates mentioned in parties' testimony is FERC's determination that pricing methodologies cannot include "adders" that do not reflect actual, incremental costs of alternative electric energy. So. Cal. Edison Co., 71 FERC ¶ 61, 269, 62,080 (June 2, 1995).

Recently, FERC provided clarification on appropriate costs to include in avoided cost rates in cases that arose from a California law requiring utilities to offer to purchase energy from small, efficient CHP facilities. The California Public Utilities Commission (CPUC) implemented this law by setting prices utilities were required to offer to CHP generators. The prices reflected additional costs necessary to meet environmental requirements. Additionally, the CPUC required that a 10% bonus be added to the price if the facility was in a transmission or distribution constrained area, to reflect the avoided costs of upgrades. Cal. Pub. Utility Comm'n,, 132 FERC ¶ 61,047, 61,326-27 (July 15, 2010), *clarification granted & rehearing denied*, 133 FERC ¶ 61,059 (October 21, 2010), *rehearing denied*, 134 FERC ¶ 61,044 (Jan. 20, 2011).

FERC found that CPUC's pricing method did not necessarily run afoul of PURPA if certain requirements were met: the CHP facilities must obtain QF status and the rates paid to them must not exceed avoided costs. *Id.* at 61,338-39. The CPUC requested clarification from FERC regarding how to implement the California law in conformance with PURPA. CPUC argued that *short term* avoided cost determinations should not set the limit on the price that utilities must offer for CHP systems and that there could be multiple avoided cost calculations to reflect, for example, different factors such as the length of the power purchase commitments, the efficiency of a new CCCT, and the location of the CHP facility. 133 FERC ¶ 61,059, 61,262-63 (October 21, 2010), *rehearing denied*, 134 FERC ¶ 61,044 (Jan. 20, 2011).

FERC, without making conclusions regarding whether the CPUC's specific implementation strategies did or did not exceed avoided costs, offered guidance regarding whether the CPUC's "conceptual framework" was consistent with the requirements of PURPA. FERC found that the concept of a "multi-tiered" avoided cost rate is consistent with the requirements of PURPA and Commission regulations. "Both section 210 of PURPA and our regulations define avoided costs in terms of costs that the electric utility avoids by virtue of purchasing from the QF. The question, then, is what costs the electric utility is avoiding." *Id.* at ¶ 61,266. Specifically,

> 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.' 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. *Id.* at 61,267-68.

Thus, 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). For example, transmission and distribution system upgrades, which impose real costs, are not specific energy or capacity components of the alternative (avoided) energy resources; rather, they are costs that are *associated with* alternative energy and are costs that may be avoided by QF purchases. Similarly, costs uniquely attendant to fossil fuel use are not necessarily specific energy and capacity components of alternative generation resources, but are nevertheless relevant to a determination of costs that are avoided by purchasing electricity from renewable QFs.

i. FERC rules permit consideration of a QF's ability to avoid fossil fuel-related costs, and costs associated with fuel price volatility, environmental and carbon regulation, and climate change are directly associated with fossil fuel use.

FERC rules permit consideration of a QF's ability to avoided fossil fuel-related costs. In determining avoided costs, one of the factors to be taken into account to the extent practicable is "the ability of the electric utility to avoid costs, including … *the reduction of fossil fuel use*." 18 CFR §292.304(e)(3) (emphasis added). Fossil fuel use not only has associated fuel costs, but also imposes costs that can be avoided by purchasing power from renewable QFs. There are three categories of fossil fuel-related costs that renewable QFs enable the utility to avoid: costs associated with fuel price increases and volatility, costs associated with environmental regulation, and costs associated with adapting to a changing climate. UCE Exhibit 4.0(D), 7-15. Because these costs are directly related to fossil fuel use, it is proper to take them into account when setting avoided costs.

Not only does fossil fuel use impose fuel costs, but it also creates costs and risk associated with fuel price increases. Natural gas prices are at historically low levels, leading to increased reliance on fossil-fueled resources. UCE 4.0(D), lines 228-32. Because of current low prices, cost risk associated with fuel price increases is asymmetrical; that is, the chance that prices will increase is greater than the chance that prices will decline, and the risk is such that cost increases can be more extreme than price decreases. *Id.* at 233-48; UCE 6.0(S), lines 413-23. Because of the pass-through nature of fuel costs and the Company's energy balancing account, ratepayers bear the risk of fuel price increases. *Id.*at line 287. Renewable QFs on the other hand, do not require use of fossil fuels and therefore avoid both fuel commodity costs as well costs associated with fuel prices that are higher than today's forward price curve.

Like fuel price risk, the risk of environmental/carbon regulation is also asymmetrical. UCE 6.0(S), lines 425-27. And although the Integrated Resource Plan (IRP) is supposed to evaluate both the relative cost and risk benefits of different resources, "IRP analysis of costs and risks does not translate to compensation of renewable QF resources for the risk-related costs that they avoid for ratepayers." *Id.* at lines 434-35. And although the Company does not currently pay carbon regulation costs, the Company includes carbon regulation costs in its IRP well within the time horizons of renewable power purchase agreements. UCE 5.0(R), pages 23-24. Further, on June 25, the President of United States released, "The President's Climate Action Plan," which includes a Presidential Memorandum directing the United States Environmental Protection Agency to work expeditiously to complete the carbon pollution standards for both new and existing power plants, [2] making regulation costs a more likely reality in the near term. There are also significant costs associated with the climate impacts of fossil fuel use. UCE 4.0(D), pages 8-13. No party disputed evidence of the climate change-related costs imposed by fossil fuels.

Because of the risks associated with fossil fuel use, renewable QFs provide real value not just from avoided fuel costs, but also from avoided costs attendant to avoided fossil fuel use. Additionally, mitigating risk associated with fossil fuel use also imposes actual costs upon the utility and ratepayers:

> The Division's analogy is interesting. Flood risk level will depend on the location of your home: if your home is built in an area prone to flooding, it is likely that you will incur those costs and, if you are wise, you will purchase flood insurance. Given the consensus among climate scientists and the costly impacts of climate change that I discussed at

[2] http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf

> length in my direct testimony, coupled with the fact that natural gas price risk is asymmetrical, the risk that real and measurable costs associated with climate change and carbon regulation, and costs associated with asymmetrical fuel risk, will impact ratepayers is very likely.
>
> We are, in other words, in an "area prone to flooding." Modifying the Proxy/PDDRR method to pay the full capacity and energy value of a renewable QF is analogous to purchasing flood insurance if you live in a flood plain. While the QF is not compensated for all the avoidable costs, it will, at least, be compensated for the full energy and capacity value it brings to the system. And if this adjustment enables it to compete, then ratepayers will receive the benefits of their "insurance" against carbon regulation, climate change, and fuel volatility. UCE 6.0(S), pages 22-23.

Despite the fact that avoidance of fossil fuel-related risks has real value for the utility and ratepayers, parties highlighted the distinction between costs being *likely* and costs being *actual* to argue that risk-associated costs are inappropriate to include in avoided costs. *See e.g.* Tr. 244:2-3. Nevertheless, both FERC regulations and FERC orders support consideration of the length of a QF power purchase agreement in determining avoided costs. The FERC regulations implementing PURPA allow power purchase prices to be "based on cost projections for the life of the obligation as calculated at the time the obligation is incurred." Pub. Serv. Co. of Oklahoma v. State ex rel. Oklahoma Corp. Comm'n, 115 P.3d 861, 872 (Okla. 2005) (*citing* 18 C.F.R. § 292.304(d)).

Likewise, FERC found that the concept of "tiered" avoided cost rates based on the length of a power purchase agreement, among other things, was consistent with PURPA. *See* Cal. Pub. Utility Comm'n,, 133 FERC ¶ 61,059, 61,262-63 (October 21, 2010), *rehearing denied*, 134 FERC ¶ 61,044 (Jan. 20, 2011). Indeed, in order to maintain ratepayer indifference between a renewable QF power purchase agreement and alternative energy supplied by the utility, it is necessary to take longer term risk and associated costs into account. UCE 5.0(R), lines 484-97.

B. With regard to long-term renewable QF power purchase agreements (20-plus years), "ratepayer indifference" implicates more than a short term view of

avoided costs based on projected market energy prices.

Ratepayer indifference represents the principle that QF purchase rates are to be set no higher and no lower than the costs the utility would incur to purchase or produce alternate power in order to both protect ratepayers and encourage independent power generation.[3] Ratepayer indifference means that ratepayers should be economically indifferent to the source of a utility's energy over the course of the power purchase agreement—something they *cannot* be if risk is not taken into account. In considering renewable QF avoided costs, it is necessary, in order to maintain ratepayer indifference, to consider what costs, in total, the utility avoids over the course of a renewable power purchase agreement. Most renewable power purchase agreements last at least 20 years. UCE 4.0(D), lines 255-56. On the other hand, non-renewable resources have not locked in long term QF contracts in Utah. *See* Tr. 31:19-22.

C. Costs are not irrelevant (or not actual) because they are not known and measurable.

Although the Company argued that costs that are not "known and measurable" violate PURPA (Duvall Rebuttal, lines 339-344), Mr. Duvall admitted on cross examination both that he did not actually know whether that was a requirement of PURPA, and that the Company's own avoided costs calculations include costs that are unknown and forecasted, rather than known and measured, including fuel and electricity prices. Tr. 31:6-8, 55-56. Furthermore, Mr. Duvall

[3] "PURPA requires an electric utility to purchase power from a QF, but only if the QF sells at a price no higher than the cost the utility would have incurred for the power if it had not purchased the QF's energy and/or capacity, i.e. would have generated itself or purchased from another source. The intention was to make ratepayers indifferent as to whether the utility used more traditional sources of power or the newly-encouraged alternatives." *SoCal Edison*, 71 FERC P 61,269, 62,079-80 (June 2, 1995). *See also* Amer. Paper Inst., Inc. v. Amer. Elec. Pow. Serv. Corp., 461 U.S. 402, 417-18 (1983) ("Under these circumstances it was not unreasonable for the Commission to prescribe *the maximum rate authorized by PURPA*. The Commission's order makes clear that the Commission considered the relevant factors and deemed it most important at this time to provide the maximum incentive for the development of cogeneration and small power production, in light of the Commission's judgment that the entire country will ultimately benefit from the increased development of these technologies and the resulting decrease in the Nation's dependence on fossil fuels." (Emphasis added.))

recognized that there is value in securing a long-term renewable QF power purchase agreement that is not accounted for in avoided cost pricing. Tr. 55-60. Specifically, there is known, though hard to measure, value in tying down prices today for the next 20-plus years because of avoided fuel price volatility, fuel price increases, and environmental regulation and carbon costs. UCE 4.0(D), lines 122-32; UCE 5.0(R), lines 484-97.

Because renewable QFs avoid costs for 20 or more years, the Company's avoided cost pricing methodology must account for the valuable risk mitigation provided by renewable QFs. Because these risk-associated avoided costs are hard to quantify, Utah Clean Energy proposed accounting for them by paying QFs, based on capacity contribution, beginning in the first year of the power purchase agreement, as well as basing energy prices, for the duration of the power purchase agreement, on un-capped GRID results:

> I recognize that it may be too difficult to put a specific value on these avoidable costs based on the record in this Docket. However, my testimony has shown that there are real costs that are avoided by renewable QFs. Therefore, in recognition of these avoidable costs, it is critical to, at a minimum, modify the Proxy/PDDRR method as Utah Clean Energy has proposed to grant renewable QFs the full value of their capacity and energy contributions for the QF contract period. While this does not pay the QFs for all their avoidable costs, it is a fairer method than the current Proxy/PDDRR method, and it is possible that QFs may be able to compete, bringing significant benefits to Utah and Utah ratepayers. UCE 6.0(S), lines 469-77.

Further support for this recommendation is provided below.

II. AVOIDED COST PRICING FOR RENEWABLE QFS PURSUANT TO THE PROXY/PDDRR METHODOLOGY SHOULD INCLUDE PAYMENTS FOR CAPACITY CONTRIBUTION AND UNCAPPED ENERGY PAYMENTS FOR THE DURATION OF THE POWER PURCHASE AGREEMENT.

A. Because of its heavy reliance on market purchases, the Company is in a constant period of resource deficiency and therefore renewable QFs are entitled to capacity payments beginning in the first year of power purchase agreements.

The Company is currently in a state of capacity deficiency. Tr. 29:16-18. Until the next physical deferrable resource comes online in 2024, and, in fact, in every year thereafter, the

Company plans to meet a significant portion of its capacity needs through market purchases or Front Office Transactions (FOTs).[4] *Errata to* UCE Exhibit 5.1(R); Scatec Surrebuttal Exhibit A (*2013 IRP* pages 99 and 229). The Company acknowledges that it is able to defer investments in new plant construction through its market purchases and that, but for its FOTs, it does not have sufficient capacity to serve its needs and reserves. Tr. 67:3-7, 12-16. Therefore, the Company is in a "constant period of resource deficiency." UCE 6.0(S), lines 314-17.

When a utility is capacity deficient, it must pay a QF for capacity. "If a qualifying facility offers energy of sufficient reliability…to reduce firm power purchases from another utility, then the rates for such purchases will be based on the avoided *capacity and* energy costs." FERC Order No. 69, 30,128, 30855 (February 19, 1980) (emphasis added). The Company's proposed avoided cost methodology does not provide payment for capacity contribution until 2024, however. Duvall Rebuttal, line 210.

Because the company is currently able to reduce firm power purchases through QF contracts, it is appropriate and necessary to provide QFs with an explicit capacity payment beginning in the first year of the power purchase agreement. Furthermore, it is inaccurate to presume that GRID-produced energy payments based on avoided market purchases actually compensate for capacity (see below).

i. Because long-term renewable QF contracts provide physical reliability benefits and mitigate risk, renewable QFs should receive payment for the risk-mitigating, physical capacity they contribute based on the capital

[4] According to PacifiCorp's 2013 Integrated Resource Plan, the Company's 2013 resource mix is 7.9% FOT by capacity, and the projected 2022 resource mix is 11.7% FOT by capacity. In the Company's 2008 IRP proceeding, the Commission explained that it was "concerned with the Company's stated confidence in managing the risk associated with reliance on the market for a significant portion of its customers' power requirements… These decisions appear to leave little room for forecast error related to prices and loads. Meanwhile, the Company is asking for an energy cost adjustment mechanism in a separate docket." Docket No. 09-2035-01, In the Matter of the Acknowledgment of PacifiCorp's Integrated Resource Plan, *Report and Order on the 2008 Integrated Resource Plan*, 29-30 (April 1, 2010). That IRP increased reliance on FOTs only up to 7.7 percent by 2018. *Id.* at 28. The extent of PacifiCorp's current reliance on FOTs therefore appears to be unprecedented.

costs of the deferrable resource.

The Capacity contribution of a QF is categorically different than capacity purchased through FOTs. The Company relies on FOTs for both capacity and energy. UCE 6.0(S), lines 263-69. The Company acknowledged that what is being deferred in GRID when the displaced resource is an FOT is the Company's forward price curve, *not* actual committed capacity. *See* Tr. 49:19-24. The Company confirmed that in the first six years, the forward price curve reflects currently available market price quotes, but that after year seven, the forward price curve does not reflect actual contracts that could tie down prices through the planning term. Tr. 52:1-6, 51:4-7. Market prices, particularly during the later years of the planning horizon, are unknown. Tr. 55:21-25, 56:1-5. Furthermore, the Company has not sought after or acquired long-term firm market contracts that provide long-term assurance of capacity. Tr. 50:1-25, 51:1-25, 52:1-6; *See also* Tr. 67:19-23 ("The purchases are not locked in, but the markets are there and our access to markets is known").

There is not sufficient evidence to conclude that QFs currently receive a capacity payment through the GRID energy payment stream. The Company's *access* to firm market energy products over the planning term does not provide any information about the Company's avoided costs of deferring committed capacity. Access to capacity is categorically different than committed capacity from a long term power purchase agreement with a physical resource. This position is not only supported by evidence in this case, but also by a PURPA case decided by the Oklahoma Supreme Court in 2005. In that case, the court held that the Oklahoma Corporation Commission's refusal to base avoided capacity costs on wholesale market prices was supported by evidence that it was "inappropriate and risky for a utility to rely on purchases at projected wholesale market prices for a significant portion of its resource needs without *locking in a price* *and assuring availability through a contract or other binding agreement*." Pub. Serv. Co. of Oklahoma v. State ex rel. Oklahoma Corp. Comm'n, 115 P.3d 861, 877 (Okla. 2005) (emphasis added).

GRID output further casts doubt on there being a capacity component included in a GRID-generated energy payment because the GRID price for summer, daytime solar energy is nearly identical to the fuel cost of a CCCT. Work-papers filed with UCE 4.0(D), *Exhibit C*, Tables 1 and 5. Mr. Millsap also noted that GRID-generated energy prices are below the fuel cost of a CCCT. Millsap Direct, lines 38-41.

Renewable QF resources not only lock in prices for 20-plus years, they also provide physical resources that contribute capacity value toward meeting the Company's planning reserve requirements. UCE 4.0(D), lines 255-56, UCE 6.0(S), lines 221-23. Furthermore, purchases from renewable QFs mitigate the risk of relying on the market for capacity resources. UCE 6.0(S), lines 382-423; *see also* Tr. 68:3-11, 58:2-4. Therefore, GRID-calculated energy prices do not reflect the true capacity value (avoided capacity costs) the utility receives through QF purchases during periods of resource "sufficiency."

Access to market capacity, represented by hypothetical market prices, does not provide a distinct capacity payment based on actual costs of avoided capacity. The capital costs of physical resources, on the other hand, provide insight into the costs of committed capacity avoided by QFs. In order to compensate renewable QFs for the physical capacity they contribute to the utility, *as well as the fact that the Company avoids significant risk associated with market purchases*, capacity payments should be calculated for each year of the contract, based on the appropriate percentage of the capital cost of the deferrable resource (based on the capacity value calculation method discussed in Section III, below).

B. Avoided energy costs, pursuant to the Proxy/PDDRR method, should be based on displacement differential GRID runs (the Commission should maintain the status quo).

During the hearing, the Company clarified for the record that GRID energy prices are not capped in the resource sufficiency period for firm power. Tr. 65:1-18. Therefore, current practice appears to be consistent with Utah Clean Energy's energy payment recommendation:

> It is inaccurate to place an additional cap on an energy price that has already been adjusted based on the displacement of a portion of the next deferrable resource. Given that GRID already takes the energy cost impacts of partially displacing the deferrable resource into account in its output, it is unreasonable to further reduce energy payments to QFs based on the assumption that, once the deferrable resource comes online, the QF will only displace that resource.
>
> This problem is exacerbated because PacifiCorp's 'preferred portfolio' in its IRP relies heavily on front office transactions through the 2032 planning horizon, even after the next IRP capacity resource is added. …
>
> If a QF provides energy during periods when the Company is purchasing Front Office Transactions, it is probable that the QF will be avoiding these purchases, rather than generation from a Company-owned gas plant. Under the current scenario, where the Company is relying heavily on market purchases even after the 2024 resource is added, QFs will likely still displace market purchases. Therefore, it is not reflective of avoided costs to cap the entire energy payment based on the dispatch cost of the deferrable resource. UCE Exhibit 5.0(R), lines 281-99.

The Office of Consumer Service's position that, "Once the QF's are receiving the capacity payment, they are being paid to supply energy based on the capital and operating costs of the avoided unit" (OCS 1S, lines13-14), does not bear scrutiny in light of the resources actually deferred in the resource "sufficiency" period, particularly given the Company's heavy reliance on FOTs.[5]

---

[5] The facts here are analogous to the facts in the Oklahoma case at note 4, *supra*. "The Commission's order moves seamlessly from finding that a peaking unit would be the most appropriate capacity addition to PSO's system to using the heat rates of a peaking unit as the basis for calculating energy payments. There seems to be an underlying assumption in the Commission's order, the basis of which is neither expressed nor evident to the court, that if a peaking unit is used for capacity payments, then a peaking unit's heat rate must serve as the basis for energy payments. Utilizing a single proxy unit for both calculations makes sense if the utility's energy needs match

Based on the record in this proceeding, it is Utah Clean Energy's recommendation that, under the Proxy/PDDRR method, capacity contribution must be compensated in each year of the power purchase agreement, capacity costs should be based on the capital costs of the deferrable resource (based on the capacity value methodology discussed below), and energy costs should be calculated through GRID displacement differential model.

III. A RELIABILITY-BASED CAPACITY VALUATION METHOD, SUCH AS THE ELCC OR CFAM, IS THE PROPER METHOD FOR EVALUATING THE CAPACITY CONTRIBUTION OF RENEWABLE RESOURCES.

For the reasons discussed herein, there is sufficient evidence before the Commission to determine that the appropriate capacity valuation methodology for renewable QF resources is either the Effective Load Carrying Capability (ELCC) method or the Capacity Factor Approximation Method (CFAM), using loss of load probabilities for the top 10% load hours (or both), as described at UCE 5.0(R), lines 187-225.

"An important aspect of the benefits of renewable electricity is its capacity value, or the ability of renewable generators to reliably meet demand. …Therefore, assessing the adequacy of renewable generation technologies and consequently estimating their capacity value is crucial for accurate reliability and planning of power systems." UCE 4.1(D), page 1. The NREL "reliability-based" capacity valuation methods are designed to provide an accurate assessment of a renewable resource's "ability to reduce the probability of a loss of load event (LOLE) and maintain system reliability." UCE 4.0(D), lines 364-66. As such, they are designed to provide a full picture of the system benefits (avoided costs) of additional renewable resources.

---

the cogenerator's energy output, but where as here the cogenerator will supply a great deal more than the utility's capacity requirements, the rationale for using a unit specific approach to both capacity and energy payments is not clear." 115 P.3d 861 at 881-82. In the case currently before this Commission, the evidence shows that the output of the renewable QF will generally displace market purchases, and avoided energy costs should be based on the costs of the resource actually deferred, as determined by GRID displacement differential runs. UCE Exhibit 5.0(R), lines 280-99.

On the other hand, "capacity contribution," as defined by the Company is not a concept discussed in any of the studies on the record that address capacity value. *See* UCE Exhibit 4.1(D) and Exhibit DPU 2.1R. RMP admits that it created this method and is not aware of any other entity that uses it. Tr. 33:13-14, 40:4-7. The Company's method, as discussed below, ignores real value provided by renewable QFs.

In this docket, the Company is proposing that the Commission approve a capacity valuation method for renewable resources that has wider applicability in, but has not been vetted through, the IRP process. *See* Tr. 33:17-21. There is no evidence that the Company's proposed "capacity contribution" method is a method that is generally accepted among utilities or the energy industry in general.[6] Tr. 39:18-25, 40:1-7. On the other hand, there is evidence that the ELCC method and the CFAM are generally accepted by the industry and superior to the Company's methods. DPU 2.0R, lines 86-89; OCS 1R, lines 20-22; UCE 4.0(D), lines 396-98; SunEdison Rebuttal, page 4.

The Company's method, which calculates a 90% exceedence probability, is designed to assess capacity "value" solely in terms of the lowest amount of megawatts available in 90 out of in 100 heavy load hours. Tr. 36:22-25, 37:1. Nevertheless, the Company acknowledges that there is additional capacity value supplied by renewable resources in other hours of the year. Tr. 35:9-12. Additionally,

> When capacity values…are incorrectly calculated, this has a direct impact on PacifiCorp's resource planning efforts and results in inaccurate reserve margin planning; this directly translates to ratepayers paying for unnecessary ancillary services and reserves. If modeled correctly to truly reflect…capacity value, RMP ratepayers will pay the true avoided costs associated with accomplishing PacifiCorp's Integrated Resource

[6] Parties have presented two different studies regarding capacity valuation—one by the National Renewable Energy Laboratory (NREL) and one by the Institute of Electrical and Electronics Engineers (IEEE)—neither of which described a capacity valuation study like the one presented by Rocky Mountain Power in this docket. *See* UCE 4.1(D) and DPU 2.1R.

Planning (IRP) objectives. SunEdison Rebuttal, page 4.

See also DPU 2.0R, line 152-73 ("Thus, the value a resource adds to the Company's choice of a least cost/least risk preferred portfolio is based on the resource's contribution in all hours of the year.").

The Company's method ignores actual value, both in terms of system reliability from a planning perspective as well as actual monetary value in terms of the value of energy in heavy load hours, provided by physical renewable resources—value that is highly relevant to a determination of avoided costs. But the Company itself acknowledges that the purpose of this docket is to evaluate "what costs *in total* does the utility avoid." Tr. 39:11-15 (emphasis added).

Utah Clean Energy, the Division, the Office, and SunEdison, all support using NREL methods, specifically the ELCC method and the CFAM, to reasonably evaluate the capacity value of renewable resources for avoided costs purposes. *See e.g.*, DPU 2.0R, lines 86-89; OCS 1R, lines 20-22; UCE 4.0(D), lines 396-98; SunEdison Rebuttal, page 4.The Company itself, though it opposes use of the ELCC method or CFAM, uses NREL data for its capacity valuation study (Tr. 42:19), implicitly acknowledging industry reliance on NREL sources. Non-Company parties agree that the ELCC method provides the most accurate assessment of capacity value, but that the CFAM is most accurate "approximation method." *See, e.g.* DPU 2.0R, lines 138-62.

Utah Clean Energy recommends that the Commission approve the ELCC method and/or the CFAM and supports the recommendations of the Division and the Office to set interim capacity values until parties can review the Company's completed capacity valuation according a to Commission-approved method. *See* OCS 2S, lines 121-42; DPU 2.0R, lines 191-208.

IV. IN ORDER TO ENCOURAGE QF DEVELOPMENT, THE COMMISSION MUST ALLOW RECS TO EITHER REMAIN WITH THE QF DEVELOPER OR BE PURCHASED BY THE UTILITY AS A SEPARATE COMMODITY FROM ELECTRICITY.

Just as cogeneration QF facilities produce both electricity and steam commodities, renewable QFs produce both electricity and environmental attribute commodities.[7] Renewable Energy Credits (RECs) are commodities with value. Tr. 201:18-19. Although the Company and the Office argue that PURPA's "purchase obligation" constitutes "compensation" for RECs produced by renewable QFs (Tr. 112:7-12, 201:4-6), no witness for either party could explain how, in monetary terms, the utility would not be acquiring a valuable commodity for more than zero dollars. Tr. 121:10-12, 126:21-24, 201:1-6. In addition to being inconsistent with FERC and Utah Commission precedent (Scatec Direct, pages 4-7), this position is bad public policy and thwarts PURPA's purpose of encouraging cogeneration and small power production because it eliminates an important revenue stream for renewable QFs.

The Company's justification for automatic REC and electricity bundling is, "if the Company and its customers own the purchase obligation because the resource is renewable, the Company and its customers should also own the characteristic that defines the resource as renewable, which is the REC." Tr. 112:16-19. This justification does not withstand legal analysis as it is impossible for the REC, as argued by the Company, to encompass the characteristic that created the purchase obligation.

First, PURPA (a federal law) was enacted before states created RECs as commodities. UCE 4.0(D), lines 553-55. Second, renewable attributes do not create a purchase obligation under PURPA; Congress created PURPA's purchase obligation in order to overcome utility reluctance to purchase electricity from independent power producers. <u>FERC v. Mississippi</u>, 456 U.S. 741, 750-51 (1980). Third, a state-created REC does not define a resource as renewable under PURPA, or even determine its eligibility to qualify for avoided cost pricing. 18 CFR §

[7] Some cogenerators are also renewable resources under Utah Code.

292.203-04; *cf.* U.C.A. § 54-17-601, 603. Indeed, non-renewable cogeneration facilities that may not generate RECs may still qualify under PURPA.

Additionally, the Company argues, although renewable QFs have value distinct from and additional to non-renewable QFs because of RECs, because PURPA does not mention RECs, it would be discriminatory to pay a QF for RECs in addition to compensation for energy and capacity. Tr. 120:17-25, 121:1-12. This is not only nonsensical, but it directly contradicts both FERC and Utah Commission rulings that describe RECs as separate commodities from the electricity commodity contemplated by PURPA. *See* Amer. Ref-Feul Co., 107 FERC ¶ 61,016, para. 16 (2004); Docket No. 10-035-15, *In the Matter of the Complaint of Cottonwood Hydro, LLC v. Rocky Mountain Power* (Report and Order, issued May 27, 2010), page 9.

It is inconsistent with federal law, Utah law, public policy, and general principles of fairness to take something of value, created by one entity, and require that it be owned by another entity, without compensation. Furthermore, it discourages renewable qualifying generation in Utah. Utah Clean Energy recommends that the Commission allow renewable QFs to keep RECs associated with electricity production unless the purchase price compensates RECs as a separate commodity. A REC price could be based on the Company's IRP assumptions about carbon prices, as described in UCE 5.0(R), lines 470-79.

V. INTEGRATION COSTS

There is insufficient evidence to charge solar QFs integration costs. While the Company argued that wind integration charges are an appropriate proxy for solar, the only evidence provided to support this showed that solar resources may, when aggregated into high enough penetrations, impose more costs on a dollars per megawatt basis than lower penetrations. Duvall Rebuttal, Lines 315-17; Tr. 31:2-5. Furthermore, the Division provided evidence that solar generation is more predictable than wind generation, but their analysis is likewise insufficient to support charging solar integration costs when there is no evidence that the Company actually incurs integration costs for solar resources. UCE 5.0(R), lines 352-54.

The Commission must find, based on the evidence in the record, that there is not currently a solar integration cost. Nevertheless, because parties acknowledge that solar resources have the potential to create integration costs, the Company should conduct a study, utilizing a technical review committee, in support of its proposal to charge solar facilities integration costs and to justify a cost per kilowatt hour. *See, e.g.* OCS 1D, lines 279-85.

VI. THE MARKET PROXY METHOD SHOULD BE USED WHEN THERE ARE RENEWABLE RESOURCE TARGETS IN THE IRP.

The Company argued that the Market Proxy method is out of date because there are no "cost-effective" renewables in the IRP. Duvall Direct, lines 188-89. Utah Clean Energy is concerned that, given current planning and modeling assumptions, the IRP is unable to recognize the long-term risk mitigation of renewable resources. UCE 4.0(D), lines 269-74; Tr. 228:24-25, 229:1-6. UCE supports using Proxy/PDDRR method when there are no cost-effective renewable resource targets in the IRP, but recommends that the Commission retain a modified form of the Market Proxy method for use when there are renewable resource targets. UCE 4.0(D), lines 292-94. Specifically, if the Commission finds that IRPs include cost-effective renewable energy resources after a thorough review of costs and risks, avoided cost rates for renewable energy QFs should be based on "proxy" costs of corresponding renewable energy sources. Tr. 230:1-3. Because IRPs are updated every two years, IRP resource cost assumptions can be used as reasonable resource proxy costs. Tr. 230:9-11. And because of ongoing price declines, solar proxy costs should be determined by the most recently published industry data. Tr. 230:12-19.

Renewable resources are uniquely suited for the proxy method. Using a resource proxy for each type of renewable resource satisfies the conditions highlighted by the Division as necessary for using the market proxy method. DPU 2.0D, lines 171-75. By comparing wind to wind, solar to solar, etc., the operating characteristics of the proxy plant closely match those of the QF being evaluated. Tr. 231:13-15. Because renewable resources are highly modular, and can be added in 1 MW increments, it is possible for a QF to replace the entire capacity and energy of the proxy plant. Tr. 231:15-19. Adding a renewable resource earlier than an IRP plan may change system operation, but many things change plant additions and operations, including changing load, changing gas prices, market purchase prices, levels of efficiency achieved, etc., and it is not clear that adding a renewable QF resource is significantly more disruptive than these events. Tr. 231:20-25, 232:1-6.

The Commission's reasoning approving the Market Proxy method in the 2005 Order in Docket 03-035-14 still applies. Tr. 230:20-25, 231:1; UCE 6.0(S), lines 82-127. Additionally, there are good reasons to acquire renewable resources earlier, including taking advantage of federal tax incentives, securing optimal resource sites and transmission availability, and hedging against purchases and fuel price risk. Tr. 231:1-7.

The Commission found that this method is in the public interest when there are cost-effective renewables in the IRP. Given that, and given that the proxy resource method (relative to other avoided cost pricing methods) encourages QF generation, Utah Clean Energy recommends that it remain a viable avoided cost pricing method, though dormant for the time being.

VII. QUEUE MANAGEMENT ISSUES

This docket brought to light pricing implications with how the Company manages the queue for QF pricing. UCE 6.0(S) 517-26. The Commission should direct the Company to file their current queue management process and allow interested parties to comment. A Commission-approved queue management process should then become part of the Schedule 38 tariff.

CONCLUSION

Utah Clean Energy recommends that the Commission approve the following components of avoided cost pricing for renewable qualifying facilities in Utah.

1. Utilize a modified Market Proxy method (proxy resource method) when cost-effective renewable resources are called for in the IRP and a modified Proxy/PDDRR method when cost-effective renewables are not part of a least cost, least risk plan.
2. Under the Proxy/PDDRR method, utilize either the ELCC method or the CFAM (using loss of load probability for the top 10% load hours) to evaluate the capacity values of renewable resources.
3. Under the Proxy/PDDRR method, utilize the displacement differential GRID runs to calculate the energy payment stream.
4. Under the Proxy/PDDRR method, base capacity payments for renewable QFs on the capital cost of the deferrable resource (adjusted for capacity value according to the ELCC method or CFAM).
5. Under the Proxy/PDDRR method, pay renewable QFs for their capacity contribution in each year of the power purchase agreements in recognition of the physical reliability benefits and risk mitigation provided by renewable QFs.
6. Allow renewable QFs to keep the RECs associated with their electricity production unless the purchase price compensates RECs as a separate commodity.

Utah Clean Energy also made the following other recommendations in this docket: do not charge solar QFs integration costs until the Company can prove it incurs them in a solar integration study; allow parties to comment on the Company's queue management policies before implementing an approved method in the Schedule 38 tariff; and finally, the Commission could approve the foregoing recommendations on a "pilot" basis (320 MW or through 2016) before evaluating results and determining whether to retain the method or make modifications.

RESPECTFULLY SUBMITTED,

____

Sophie Hayes
Attorney for Utah Clean Energy