Adam S. Long (14701)
(along@shutah.law)
SMITH HARTVIGSEN, PLLC
257 East 200 South, Suite 500
Salt Lake City, Utah 84111
Telephone: (801) 413-1600
Facsimile: (801) 413-1620
Counsel for the Renewable Energy Coalition

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of Rocky Mountain Power's Proposed Tariff Revisions to Electric Service Schedule No. 37, Avoided Cost Purchases from Qualifying Facilities	Docket No. 17-035-T07
In the Matter of Rocky Mountain Power's 2017 Avoided Cost Input Changes Quarterly Compliance Filing	Docket No. 17-035-37 **DIRECT TESTIMONY OF JOHN LOWE**

The Renewable Energy Coalition, (the "**Coalition**") hereby submits the attached Direct Testimony of John Lowe on behalf of the Coalition in this combined docket.

Respectfully submitted this 3rd day of October, 2017.

SMITH HARTVIGSEN, PLLC

/s/ Adam S. Long
Adam S. Long
Attorney for Renewable Energy Coalition

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing was served on this 3rd day of October, 2017 upon the following as indicated below:

Via hand delivery and email to:

UTAH PUBLIC SERVICE COMMISSION
c/o Gary Widerburg, Commission Secretary
160 East 300 South, Fourth Floor
Salt Lake City, Utah 84111
psc@utah.gov

Via e-mail to:

Bob Lively	bob.lively@pacificorp.com
Jeffrey K. Larsen	jeff.larsen@pacificorp.com
R. Jeff Richards	robert.richards@pacificorp.com
Yvonne R. Hogle	yvonne.hogle@pacificorp.com
Rocky Mountain Power	datarequest@pacificorp.com
Patricia Schmid	pschmid@agutah.gov
Justin Jetter	jjetter@agutah.gov
Chris Parker	chrisparker@utah.gov
Artie Powell	wpowell@utah.gov
Erika Tedder	dpudatarequest@utah.gov
Division of Public Utilities	
Michele Beck	mbeck@utah.gov
Robert Moore	rmoore@agutah.gov
Steven Snarr	stevensnarr@agutah.gov
Office of Consumer Services	
Sophie Hayes	sophie@utahcleanerergy.org
Kate Bowman	kate@utahcleanenergy.org
Utah Clean Energy	

/s/ Adam S. Long

TESTIMONY
OF
JOHN LOWE

FOR

RENEWABLE ENERGY COALITION

October 3, 2017

Docket No. 17-035-T07
Docket No. 17-035-37

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is John R. Lowe. I am the director of the Renewable Energy Coalition (the "**Coalition**"). My business address is P.O. Box 25576 Portland, Oregon 97298.

Q. Please describe your background and experience.

A. In 1975, I graduated from Oregon State with a B.S. I was employed by PacifiCorp for thirty-one years, most of which was spent implementing the Public Utility Regulatory Policies Act ("**PURPA**") regulations throughout the utility's multi-state service territory. My responsibilities included all contractual matters and supervision of others related to both power purchases and interconnections. Since 2009, I have been directing and managing the activities of the Coalition as well as providing consulting services to individual members related to both power purchases and interconnections.

Q. On behalf of who are you appearing in this proceeding?

A. I am testifying on behalf of the Coalition.

Q. Please describe the Coalition and its members.

A. The Coalition was established in 2009, and is comprised of nearly forty members who own and operate or are in the process of developing - small renewable energy generation qualifying facilities ("**QFs**") in Oregon, Idaho, Montana, Washington, Utah, and Wyoming. Several types of entities are members of the Coalition, including irrigation districts, waste management districts, water districts, electric cooperatives, corporations, and individuals. Most are small hydroelectric projects, but the membership also includes biomass, geothermal, solid waste, and solar projects.

Q. Please summarize your testimony.

A. The Coalition recommends that the Commission allow QFs the option to sell renewable power at fair, just and reasonable avoided cost prices or rates based on the costs of Rocky Mountain Power's[1] next planned renewable resource acquisitions. QFs help defer Rocky Mountain Power's energy, capacity and renewable resource needs, and should be fully compensated for the value of the electricity that they cause the utility to avoid. QFs also help Rocky Mountain Power defer or avoid transmission upgrades, and should be compensated accordingly.

Specifically, I recommend that the Commission continues to utilize the current Schedule 37 ("**Grid/Proxy**") and Schedule 38 ("**Proxy/PDDRR**")[2] methodologies, but revise them to allow all QFs to choose between renewable and non-renewable avoided cost rates when Rocky Mountain Power is planning to acquire new renewable resources. If the Commission moves to a Schedule 38 methodology for calculating Schedule 37 avoided cost rates, Rocky Mountain Power should also offer a renewable rate to all QFs based on the costs of its next planned renewable resource. Rocky Mountain Power agrees that there should be a renewable rate available for at least some renewable QFs, but has proposed a

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1 For simplicity, Rocky Mountain Power, PacifiCorp, and Pacific Power are collectively referred to as Rocky Mountain Power.

2 Rocky Mountain Power uses a Partial Displacement Differential Revenue Requirement ("**PDDRR**") methodology to determine its avoided energy costs.

variety of restrictions that diminish its usefulness and discriminate against Utah QFs.

Q. Please summarize Rocky Mountain Power's requests in this case.

A. Rocky Mountain Power has proposed a significant and unprecedented change in its Schedule 37 pricing methodology, as well as other changes to the avoided cost rates inputs and assumptions that would only offer avoided cost prices in limited circumstances.[3]

First, Rocky Mountain Power proposes to replace the existing Grid/Proxy methodology for setting avoided cost rates for Schedule 37 with the Proxy/PDDRR methodology used to set Schedule 38 prices. This change by itself results in huge avoided cost rate decreases for baseload (about a 15% reduction) and solar generation (about a 30% reduction) QFs. This reduction is due, in part, to the company's reliance on its entire QF queue when determining indicative Schedule 38 pricing and should be revised rather than expanded.

Second, Rocky Mountain Power proposes to only allow renewable resources of the same kind to replace the next deferrable "like" renewable resource identified in its integrated resource plan ("**IRP**")— after accounting for the queue of potential QFs—preventing Utah QFs from being able to defer a single kilowatt of the Company's over 1,100 MW of planned Wyoming wind. This effectively expands the "like" provisions used in the Schedule 38 method to the Schedule 37 method.

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3 Published rates for Schedule 37 are available to cogeneration facilities up to 1 megawatt ("**MW**") and other small QFs up to 3 MWs.

Third, Rocky Mountain proposes to ignore the planned acquisition of 1,100 MW of wind and transmission in Wyoming when determining avoided cost prices.

Finally, Rocky Mountain Power proposes to retain renewable energy certificates ("**RECs**") generated from renewable resources, extend QF pricing beyond the IRP period, and update the inputs for market prices of electricity and gas, integration costs for wind and solar QFs, and the capacity contribution for intermittent QFs.

Q. What are your specific responses to Rocky Mountain Power's filing?

A. Regarding Schedule 37, Rocky Mountain Power has not demonstrated that moving away from the proxy methodology used in the current Schedule 37 would more accurately calculate avoided cost rates for small QFs. Regarding Schedules 37 and 38, Rocky Mountain Power has demonstrated that a separate renewable avoided cost rate should be used for renewable QFs. This renewable rate, however, should be available to all renewable Utah QFs, and should not be limited to only those types of generation that Rocky Mountain Power is planning to acquire in its IRP. The renewable rate for all Utah QFs should be based on the next planned resource, which currently is the Wyoming wind resources. According to the Commission's past orders, Rocky Mountain Power is not entitled to retain RECs absent a negotiated agreement to do so. Finally, while the Coalition has significant concerns with Rocky Mountain Power's reliance upon its entire QF queue, its mechanism for extending QF pricing beyond the IRP period, and use of its own in-house official forward price curve, we are not raising any specific recommendations to these elements at this time. The Coalition reserves the right to review the testimony of other witnesses on these issues.

The Coalition's specific proposals are:

- The Commission should continue to use Rocky Mountain Power's Grid/Proxy methodology for setting small Schedule 37 QF rates, rather than the Proxy/PDDRR methodology used for Schedule 38 QF rates. Rocky Mountain Power's avoided cost rates for Schedule 37 are already too low, and fail to fully compensate QFs for their full capacity and energy value. Rocky Mountain Power's proposal will further exacerbate this inequity and result in less transparency in the determination of contracted prices.

- Regardless of whether the current Grid/Proxy approach or a Proxy/PDDRR methodology is used, a renewable QF under Schedules 37 and 38 should have the option of being paid based on either a renewable avoided cost rate or a non-renewable avoided cost rates. Rocky Mountain Power agrees in principle that at least some renewable QFs should be able to choose between a renewable and non-renewable avoided cost rate.

- A renewable rate should be offered to all renewable QFs instead of limiting renewable rates to only those QF resource types in which Rocky Mountain Power's IRP identifies a need for a renewable resource of exactly the same type. If Rocky Mountain Power has a renewable resource need for wind in 2020, then landfill waste, hydroelectric or solar generation can defer that resource need and should be appropriately compensated for the value of their renewable power. This is different from Rocky Mountain Power's proposal, which limits renewable rates only to "like" resources.

- If a renewable QF chooses to be paid a renewable avoided cost rate, then the QF should keep its environmental attributes, including RECs during the early years in which they are deferring market purchases. A QF being paid a renewable rate, however, should transfer its RECs during the later years in which they are deferring a renewable resource acquisition. When the renewable QF is paid a non-renewable rate based on the costs of market purchases and a gas plant, then they should keep the RECs in all years. This is consistent with Rocky Mountain Power's proposal.

- Utah renewable QFs should be paid avoided cost rates based on the costs of deferring Wyoming wind, plus associated transmission. Rocky Mountain Power's next planned resource is Wyoming wind, which requires the construction of hundreds of millions of dollars of new transmission to wheel the power to load. As this is the next avoidable resource, QFs regardless of their location should be paid rates based on these costs. This is different from Rocky Mountain Power's proposal, which seeks to prevent Utah QFs from being paid for the full value of their renewable power.

Q. Is the Coalition sponsoring any other witnesses in this proceeding?

A. Yes, Neal Townsend is presenting testimony on Rocky Mountain Power's proposal to limit renewable avoided cost rates to only "like" resources of the same type of technology as Rocky Mountain Power is planning to acquire in its IRP. Limiting avoided cost prices by type does not adequately compensate renewable QFs for their renewable power. Revising the current Schedule 37 Grid/Proxy methodology to allow for a renewable rate is easy because it simply replaces the thermal generation unit during the resource deficiency period with the next deferrable renewable resource (which at this time is a 2020 wind generation unit plus the transmission to wheel the electricity to load). This approach could easily calculate resource specific rates for baseload, wind and solar using the capacity value and integration costs from Rocky Mountain Power's IRP.

Revising the Schedule 38 Proxy/PDDRR methodology to develop a renewable rate for all renewable resources can also be done simply, and Mr. Townsend's testimony explains how this would work. Mr. Townsend also addresses why it is unreasonable to limit renewable rates to only "like" resources.

II. <u>AVOIDED COST RATES SHOULD BE JUST AND REASONABLE FOR RATEPAYERS AND QFs</u>

Q. Do you believe that a major methodology change should be implemented that significantly lowers avoided cost rates?

A. No. Rocky Mountain Power's proposal makes me wonder what problem they are trying to solve, or what problems they may be trying to create to slow down or stop renewable non-utility owned projects. Schedule 37 rates are already at historic lows, and the Coalition fails to see any reason to change the methodology to make them even lower.

Schedule 37 rates are at historic lows for a number of reasons, including: 1) Rocky Mountain Power has eliminated capacity payments during the resource sufficiency years so that QFs are only paid market rates; and 2) Rocky Mountain Power has proposed sufficiency periods of more than a decade for certain resource technologies, even though the Company is planning on significant resource acquisitions in the next few years ($3.5 billion in investments in new Wyoming wind generation, repowered wind, and new Wyoming transmission to wheel the new Wyoming wind). In short, Rocky Mountain Power is in a major new-build cycle, but is asking the Commission to further lower avoided cost rates. This may result in a massive amount of new generation serving customers, but with either all or nearly all of it being owned, operated by Rocky Mountain Power. This is not in the best interests of ratepayers because diversity of ownership offers unique benefits to customers, and competition has resulted in lower costs.

Q. You mention that Rocky Mountain Power no longer pays QFs for capacity during the resource sufficiency years, which extend for more than a decade. Is this the case in all of Rocky Mountain Power's states?

A. No. While each state has its own unique mix of PURPA policies that must be evaluated in their totality to determine their reasonableness, it could be argued that Utah's current Schedule 37 pricing approach is worse than the approaches in Washington, Idaho, Oregon and California. Rocky Mountain Power previously paid QFs a capacity payment during all years in Utah, including a short-term capacity payment based on the costs of a peaking unit in the resource sufficiency years and a long-term capacity payment based on the costs of combined cycle combustion turbine in the resource deficiency years, but Utah changed that policy.

Washington recognizes that when utilities have a short-term capacity need, then QFs should be paid a capacity payment in addition to an energy payment. The Washington Utilities and Transportation Commission (the "Washington Commission") has recognized that Rocky Mountain Power's (dba Pacific Power) front office transactions failed to adequately reflect the capacity value of QFs, and directed the utility to include at least a minimal capacity payment based on the costs of one fourth of a simple cycle combustion turbine gas plant.[4] The Washington Commission is currently investigating its PURPA policies, including the appropriate value of capacity.[5]

Idaho has removed capacity payments during the sufficiency period for new QFs, but pays a full capacity payment during all years for existing QFs when replacement power purchase agreements are entered into. As explained by the Idaho Public Utilities Commission (the "Idaho Commission"):

> we find merit in the argument made by the Canal Companies that contract extensions and/or renewals present an exception to the capacity deficit rule that we adopt today. It is logical that, if a QF project is being paid for capacity at the end of the contract term and the parties are seeking renewal/extension of the contract, the renewal/extension would include immediate payment of capacity. An existing QF's capacity would have already been included in the

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4 WUTC v. Pacific Power & Light Co., Washington Commission Docket No. UE-144160, Order 04 at PP. 21, 31 (Nov. 12, 2015);

5 Re Public Utilities Regulatory Policies Act, Obligations of the Utility to Qualifying Facilities, WAC 480-107-105, Washington Commission Docket No. U-161024, Notice of Workshop and Opportunity to File Written Comments (Mar. 16, 2017).

utility's load resource balance and could not be considered surplus power. Therefore, we find it reasonable to allow QFs entering into contract extensions or renewals to be paid capacity for the full term of the extension or renewal. [6]

The Idaho Commission recently reaffirmed this policy. [7]

Oregon uses a similar approach to Utah, but recently recognized that existing QFs help defer capacity acquisitions, because without their continued operation, Rocky Mountain Power would need to acquire new capacity resources.[8] While a methodology to calculate this capacity value has not yet been approved, Oregon has recognized the principle that capacity payments are warranted in all years.

Q. Why are you raising this issue if the Coalition is not proposing a change to fully compensate QFs for the capacity value they provided during all years?

A. Simply to illustrate that there is ample justification to increase, rather than reduce, avoided cost rates. Rocky Mountain Power's proposals may be more "precise" and based on complex computer models, but that does not mean that they are more "accurate." In their totality, the Utah Schedules 37 and 38 currently undercompensate QFs and fail to pay any capacity during the extremely long

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6 Re the Commission's Review of PURPA QF Contract Provisions, Idaho Commission Case No. GNR-E-11-03, Order No. 32697 at 21-22 (Dec. 18, 2012) clarified in Order No. 32871 (Aug. 9, 2013).

7 Re Idaho Power Company's Petition to Modify Terms and Conditions of PURPA Purchase Agreements, Idaho Commission Case Nos. IPC-E-15-01, AVU-E-15-01, PAC-E-15-03, Order No. 33357 at 25-26 (Aug. 20, 2015).

8 Re Investigation Into QF Contracting and Pricing, Oregon Commission Docket No. UM 1610, Order No. 16-174 at 2 (May 13, 2016) ("We agree with Staff and the Joint QFs that a certain amount of capacity deferral may not be valued when utilities assume in their IRPs that existing QFs nearing contract expiration will automatically renew. We direct each utility to work with parties to address this issue in its next IRP.").

resource sufficiency period, which Rocky Mountain Power proposes to exacerbate.

III. RENEWABLE RESOURCE RATES SHOULD BE AVAILABLE UNDER BOTH SCHEDULE 37 AND SCHEDULE 38

Q. What are avoided cost rates?

A. PURPA requires electric companies to pay the "incremental cost" for energy produced by QFs. FERC regulations define the incremental costs as the cost to an electric utility, which but for the purchase from the QF, such utility would generate or purchase from another source. FERC relies upon the states to implement PURPA, and to determine avoided cost rates. FERC allows states to make adjustments to the avoided cost rate to account for a QF's unique output, and offer renewable pricing to reflect certain characteristics required by state policy.

Q. Should the Commission distinguish between renewable and non-renewable avoided cost rates?

A. Yes. All renewable QFs should be given the option to sell their renewable power to Rocky Mountain Power at a renewable avoided cost rate, whether the QF is above or below the size threshold for standard rates, and regardless of resource type. The separate renewable avoided cost rate reflects the fact that renewable QFs help utilities meet more than just their load requirements, and also help utilities comply with their state renewable portfolio standard ("**RPS**") requirement. Because some states require utilities to generate a certain amount of qualifying renewable power, it is reasonable to differentiate regardless of size between the cost of the utility's next planned renewable and non-renewable resources. Irrespective of RPS obligations, Rocky Mountain Power also has a need for a diverse resource portfolio, including both thermal and renewable resources. When a QF can defer or help Rocky Mountain Power avoid renewable resources that the Company is planning on acquiring for economic or RPS purposes, it is reasonable to pay the QF based on the costs of those renewable resource acquisitions. Also, purchasing or developing more renewable resources should aid in making a long-term transition from problematic thermal resources.

When renewable QFs are willing to sell their output and cede their RECs to the utility, those QFs allow the utility to avoid building or buying renewable generation to meet their energy and capacity needs as well as their RPS requirements. A renewable avoided cost rate could be higher than the non-renewable avoided cost rate, as renewable generation has historically been more expensive than non-renewable generation and the prices include an imputed value for RECs whose ownership is transferred to the purchasing utility when applying such renewable rates, or a renewable avoided cost rate could be lower than the non-renewable avoided cost rate, as renewable generation costs are currently quite low.

Q. Should the Commission allow QFs to choose between the renewable and non-renewable avoided cost rates?

A. Yes. QFs should be able to compare renewable and non-renewable avoided cost pricing before selecting the price stream that most closely resembles their project. When a renewable QF wishes to keep its RECs and only sell its net output to Rocky Mountain Power, then the QF should be paid a non-renewable rate based on the costs of the resource that it helps defer, including market purchases and thermal generation. Generally, RECs should be retained by the QF during the years prior to Rocky Mountain Power's next planned renewable resource acquisition date because the avoided cost rates during those years are based on the value of market purchases, which do not include RECs.

Q. Are there are other reasons to allow the QF the option to choose between a renewable and non-renewable rate?

A. Yes. Allowing renewable QFs to choose which avoided cost stream might better reflect the value of its resource. This is important to account for different types of renewable generation and QF business models, including the fact that some QFs may have already sold their RECs, or need to keep them to obtain financing. Having two different choices is more important as the utilities' resource plans change. For example, when the utilities are planning on acquiring non-renewable resources, but not renewable resources, the QF should be able to keep its RECs and sell only its power to help the utility avoid its non-renewable resource need. The opposite is also true.

Without this optionality, then certain QFs may be unable to defer the utility's actual next resource when the utilities' renewable and non-renewable resource acquisition dates do not perfectly match. Allowing QFs to choose between the separate avoided cost rate streams is consistent with FERC policy allowing states to determine avoided costs associated with utility purchases of energy from generators with certain characteristics.

Q. Can a renewable rate work with Rocky Mountain Power's current Schedule 37 methodology?

A. Yes. Oregon uses a non-PDRR methodology similar to Utah's Schedule 37 methodology, and has adopted renewable rates. Exhibit A to my testimony includes a copy of Oregon's version of Schedule 37. At the time the rates were set, the Oregon Commission determined that Rocky Mountain Power's next planned renewable resource acquisition was 2028. During the years prior to 2028, a renewable QF selecting the renewable avoided cost rate is paid market prices and keeps their RECs. Starting in 2028, the renewable QF selecting the renewable avoided cost rate is paid a rate based on the next renewable resource acquisition in the IRP, which is currently a wind resource.

In Oregon, all renewable QFs can be paid a renewable rate, with each category of renewable resource (baseload, wind and solar) having a resource specific rate calculated with adjustments for integration costs and the generic resource capacity value. For example, baseload generation has no integration costs and a higher capacity factor, so their rates are correspondingly higher to reflect this higher quality of power. Similarly, solar generation also has a higher capacity value, which is reflected in rates that are higher than wind generation (but not as high as baseload generation). The specific Oregon rates should only be viewed for illustrative purposes, because the underlying inputs and assumptions will be significantly different over time.

Q. Can a renewable rate work with Rocky Mountain Power's proposed Schedule 38 methodology?

A. Yes. I am not an expert with Rocky Mountain Power's PDDRR methodology, but Coalition witness Neal Townsend explains how this would be implemented. While it might be workable, it is un-necessary and overly complicates the determination of contract prices and the contracting process for small projects. What is critically important for both Schedules 37 and 38 is that any renewable resource type be allowed to defer Rocky Mountain Power's next renewable resource acquisition, just as how today any renewable resource type is allowed to defer Rocky Mountain Power's next thermal resource acquisition. Under Rocky Mountain Power's proposal, a solar, biomass, waste generation or hydro QF could never be paid a renewable rate if the Company is not planning on building and owning this type of generation in the near future. For example, while the IRP now includes solar and geothermal, these resources are not planned until 2031 (solar) and 2029 (geothermal).[9] Purchases from these various renewable resources can help Rocky Mountain Power avoid its next planned wind generation now and should be paid renewable rates now, rather than in almost 15 years.

Q. Should the PDDRR configuration be revised?

A. Yes. Although Rocky Mountain Power claims that the PDDRR methodology is more accurate, it also suggests that the PDDRR methodology cannot accurately calculate capacity contributions for different types of resources. To resolve this issue, Rocky Mountain Power suggests the Commission approve its "like-for-like" limitations. The Coalition disagrees. As the testimony from Neal Townsend describes, Rocky Mountain Power can configure the PDDRR methodology to work for all types of resources, and should be required to do so.

Q. Does this mean the proposed PDDRR configuration would not improve accuracy?

A. Yes. According to Rocky Mountain Power, the PDDRR method has limited effectiveness because it only accurately captures the impact of a QF when that QF is the same type (or has the same operating characteristics) as the company's next

[9] It should be noted that QFs in Utah are limited to contract terms of 15 years. Thus, Rocky Mountain Power's proposal is that a solar QF would be paid market purchases for nearly all of its contarct term, and then only be paid a higher rate for the last couple years.

planned resource. Accurate avoided cost prices, however, should be available for all resource types. Thus, Rocky Mountain Power's configuration of the PDDRR method is not more accurate than the former method because it fails to produce accurate avoided cost rates for all resource types. The more simple proxy method can be easily configured to ensure accurate avoided cost rates for all resource types

Q. Is there anything else about the PDDRR method that is unique?

A. Yes. As Rocky Mountain Power acknowledges, the PDDRR methodology relies upon the most up to date information, and does not require Commission review or acknowledgment. Thus, the inputs that determine Rocky Mountain Power's pricing may not be formally reviewed or acknowledged by the Commission.

Q. Why does this lack of review concern the Coalition?

A. The PDDRR methodology is very complex, and does not provide transparency into Rocky Mountain Power's avoided cost price calculation. Interested stakeholders must obtain expensive experts to evaluate the PDDRR configuration just to determine if Rocky Mountain Power's avoided cost price updates are accurate. This kind of "black box" computing ultimately limits participation from interested parties.

Q. Are there substantial variations in Schedule 38 indicative pricing due to "like-for-like" deferral?

A. Yes. Rocky Mountain Power's testimony includes an illustrative example where solar prices are very high in 2028 and then become negative in 2030. Rocky Mountain Power suggests that the current configuration, therefore, may not offer a workable option for calculating avoided cost prices. As Coalition's expert Neal

Townsend's testimony explains, however, these variations should be expected.

Q. Is it appropriate for Utah QFs to be paid based on Rocky Mountain Power's next deferrable renewable resource, which happens to be Wyoming wind?

A. Utah resources should be paid rates based on Rocky Mountain Power's next planned resource acquisition, including Wyoming wind. Avoided cost prices for Rocky Mountain Power have never been based upon a state-specific resources, but the next avoidable resource in their system. Rocky Mountain Power's IRP has identified 1,100 MW of Wyoming wind resources that it will acquire by the end of 2020. This should be the date upon which Rocky Mountain Power is considered renewable "deficient" and Utah QFs paid capacity costs based on Wyoming wind generation, if they elect to sell their RECs.

Q. Has the Commission contemplated economic acquisition of renewable resources, like the proposed Wyoming wind resources?

A. Yes. Although this is the first time that Rocky Mountain Power's IRP planned for a renewable resource, the Commission has already contemplated this possibility and directed Rocky Mountain Power accordingly. In 2012, the Commission excluded renewables that were acquired specifically for RPS reasons, but included cost-effective renewables. According to the Commission's order, when Rocky Mountain Power'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 [Rocky Mountain Power's] IRP planned resources."[10]

Q. Why does Rocky Mountain Power claim that no Utah resources, including

[10] Docket No. 12-035-100, Order on Phase II Issues at 43 (Aug. 16, 2013).

wind, should be paid for deferring this renewable resource?

A. Because the Company states that these capacity additions cannot be delayed or scaled down as result of a QF resource addition. Their position on the actual avoidable nature of these resources is untested and unproven.

Q. **What is your response?**

A. This is not how PURPA works. The question is not whether a single Utah QF can defer any particular resource, but what investments from QFs in the aggregate will allow the utility to avoid. Even though small amounts of capacity provided from QFs taken individually might not enable a purchasing utility to defer or avoid scheduled capacity additions, the aggregate capability of such purchases may permit the deferral or avoidance of a capacity addition. The logical result of Rocky Mountain Power's argument is that Utah QFs would never be paid any capacity because no single Utah QF can displace a Wyoming power plant.

A number of examples illustrate this point. First, small QF contracts and front office transactions are included in Rocky Mountain Power's load resource balance so as to avoid planning to construct or acquire duplicative facilities. Another example is how Rocky Mountain Power's current and proposed Schedule 37 methodologies work: a QF is paid for deferring its proportionate share of the costs of a large thermal gas plant in the deficiency period. There is no way a single 3 MW QF by itself will ever delay or scale down a 500 MW combined cycle combustion turbine plant. However, we assume that 500 MWs of small QFs could defer the construction of a new gas plant, and pay the QFs based on the avoided costs of this gas plant. Finally, assume that 1,100 MW of Utah QFs could be built at the same or lower cost as Rocky Mountain Power's Wyoming wind and transmission resources. It would be imprudent for Rocky Mountain Power to build these 1,100 MW of wind generation and the associated transmission assets instead of purchasing 1,100 MW of Utah projects that are ultimately more cost effective.

Q. Should Utah QFs be paid for Rocky Mountain Power's avoided transmission resources?

A. Yes. My understanding is that the full avoided costs should include the costs of avoided transmission in calculation of the avoided cost rates, if the QF will allow the utility to avoid those transmission costs especially in the case in which the new transmission is a necessary component of the planned resource. Therefore, if the proxy resource used to calculate a utility's avoided costs is an off-system resource, then the costs of third-party transmission are avoided, and therefore should be included in the calculation of avoided cost prices. Generally with Rocky Mountain Power, its generation has been on-system where there are no avoided transmission costs. We have a unique situation now in which Rocky Mountain Power's proxy resource, Wyoming wind, is on system, but will require transmission upgrades to deliver the output to load. These on-system Wyoming wind resources will impose transmission costs on Rocky Mountain Power and its customers, because they clearly require Rocky Mountain Power to incur costs for upgrades to network transmission on the its own system.

Excluding transmission costs required to bring generation output to load undermines the very concept of the avoided cost. These new Wyoming wind resources cannot be wheeled to load without new transmission. Thus, this new transmission infrastructure is required to bring resources to load and would be avoided if the proxy resource were avoided. As Rocky Mountain Power's IRP explains, this kind of infrastructure is often extremely expensive, faces considerable public opposition in many areas, and is time consuming to permit and construct. It is only reasonable that to the extent QFs help Rocky Mountain Power avoid, reduce or delay the costs associated with transmission to bring any proxy resource to load, the QF receive compensation for the value of that savings.

Q. Has the Commission addressed transmission costs in avoided cost rates?

A. Yes. As recently as 2012, the Commission explained, "[w]e do not dispute the conclusion from the [California Public Utility Commission] case that avoided costs based on an actual determination of expected costs of upgrades to the distribution or transmission system would be consistent with PURPA."[11]

IV. REC OWNERSHIP

Q. What has the Commission determined with respect to REC ownership?

A. In 2012, the Commission determined that QFs should retain their RECs unless otherwise provided for in a negotiated contract, in part because the avoided cost rate did not compensate QFs for anything more than capacity and energy.[12] Rocky Mountain Power asked for clarification, and the Commission denied that request, stating that the company's request "may be more appropriately addressed and vetted by the Commission when a renewable QF is actually posed to defer cost-effective renewable resources included in the IRP Action Plan."[13]

Q. What is Rocky Mountain Power proposing with respect to REC ownership?

[11] Docket No. 12-035-100, Order on Phase II Issues at 41 (Aug. 16, 2013).
[12] Id. at 9 (Aug. 16, 2013).
[13] Docket No. 12-035-100, Order Granting in Part and Denying in Part Rocky Mountain Power's Petition for Review and Clarification, at 7 (Oct. 4, 2013).

A. Rocky Mountain Power intends to keep any RECs generated from new renewable resources. Although Rocky Mountain Power's preferred portfolio does not reflect any RPS requirement, or otherwise value renewable attributes, its IRP explicitly assumes that RECs associated with new renewable resources will contribute to meeting its RPS targets in the company's western states.[14]

Q. Do Rocky Mountain Power's customers in Utah derive any benefits from these RECs?

A. Yes. Rocky Mountain Power's IRP contemplates either using its RECs in Oregon, Washington or California, or selling them to third parties. In the case of the latter, the difference between REC revenues in Utah rates and actual REC sales revenues is credited to (or collected from) Utah customers.

Q. What is the Coalition's position on REC ownership?

A. The QF should keep the RECs, unless the value of the power they are paid accounts for its renewable attributes. Therefore, if the QF is paid for power based on the costs of market purchases or a gas plant, then the QF should keep the RECs. If the QF is paid for power based on the costs of a renewable resource, then the QF should transfer the RECs to the utility.

V. ROCKY MOUNTAIN POWER'S QF QUEUE

Q. Are Rocky Mountain Power's Schedule 37 prices based upon its QF queue?

A. No. Schedule 37 prices are based upon the impact from one 10 MW baseload QF resource during the sufficiency period, and a proxy resource (currently a combined cycle combustion turbine plant) during the deficiency period.

Q. Are Rocky Mountain Power's Schedule 38 prices based upon its QF queue?

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14 Compare Direct Testimony of Daniel J. MacNeil at 11 with Direct Testimony of Daniel J. MacNeil at 23-24.

A. Yes. The modeling assumes that each QF that requests pricing will displace resources with the highest variable costs, which means that each avoided energy costs declines accordingly. As Rocky Mountain Power explains, avoided cost prices are highest for the first QF in the queue and lower for QFs later in the queue. What Rocky Mountain Power does not explain, however, is that this also means that avoided cost prices are generally lower for all of the QFs in the queue, because many of the developers that have requested pricing will never have their project come on line.

Q. Does Rocky Mountain Power's proposal to use the Schedule 38 method to calculate its Schedule 37 prices include relying upon the QF queue?

A. Yes. According to Rocky Mountain Power, prices calculated without the entire QF queue would be overstated.

Q. Do you agree?

A. No. By assuming that every single request for pricing will result in corresponding power sales, Rocky Mountain Power artificially lowers its avoided cost rates.

Q. What portion of the QF queue should be used to calculate avoided cost prices?

A. A more reasonable position would be to use the historic percentage of QFs that are constructed as compared to the entire queue, or certain completion milestones that show a proposed project is likely to be constructed—like completing the interconnection study process or executed contracts.

VI. CONCLUSION

Q. Does this conclude your testimony?

A. Yes