BEFORE THE UTAH PUBLIC SERVICE COMMISSION

In the Matter of the Application of Rocky Mountain Power to Implement Community Clean Energy Program Authorized by the Community Clean Energy Act	DOCKET NO. 25-035-06

REDACTED

REBUTTAL TESTIMONY

AND EXHIBITS

OF

KEVIN C. HIGGINS

On Behalf of

Community Renewable Energy Agency

November 13, 2025

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I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kevin C. Higgins. My business address is 111 East Broadway, Suite 1200, Salt Lake City, Utah, 84111.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Principal in the firm of Energy Strategies, LLC, a private consulting firm that specializes in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. ARE YOU THE SAME KEVIN C. HIGGINS WHO PREFILED DIRECT TESTIMONY IN THIS PROCEEDING ON BEHALF OF THE COMMUNITY RENEWABLE ENERGY AGENCY ("AGENCY")?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony responds to the direct testimonies of Division of Public Utilities ("Division") witness Timothy M. Lenell, Office of Consumer Services ("OCS") witness Anthony Sandonato, Sierra Club witness Mark Fulmer, and Western Resource Advocates ("WRA") witness Karl Boothman on the subject of resource valuation. A particular emphasis of my rebuttal is the treatment of Renewable Energy Certificates ("RECs") in the valuation of the resource(s) procured by the Utah Community Clean Energy Program ("Program").

Q. HAS YOUR REVIEW OF THE DIRECT TESTIMONIES OF THESE OTHER WITNESSES CAUSED YOU TO MODIFY THE CONCLUSIONS AND RECOMMENDATIONS IN YOUR DIRECT TESTIMONY?

A. Generally, no. However, after further consideration regarding the treatment of RECs, I offer an additional option under which the Agency may decline to retire the RECs produced by the Program resource, which I describe as a "hybrid" option. I present this option for the Commission's consideration later in my testimony.

Q. PLEASE SUMMARIZE THE PRIMARY CONCLUSIONS AND RECOMMENDATIONS OF YOUR REBUTTAL TESTIMONY.

A. I offer the following conclusions and recommendations:

- If the use of the Schedule 38 method for Program resource valuation turns out to be driven by meritless assumptions – which may very well be the case – then I agree with WRA witness Boothman that the PVRR(d) method should be used in its stead.

- There are currently two versions of the IRP that are potentially applicable to a Schedule 38 avoided cost calculation, and in both versions, the proxy solar plants used in the Schedule 38 avoided cost calculation are assumed to be eligible for production tax credits ("PTCs"), an assumption that no longer reasonably applies under current Federal law. Thus, any attempt by RMP to value the Program resource using the PTC assumptions embedded in either the 2025 Utah IRP or the Final 2025 IRP would be entirely without merit and should be rejected by the Commission.

- In the unlikely event that any solar proxy resources identified by RMP meet the new PTC eligibility requirements, the proxy resource would have to be under construction by July 4, 2026. By definition, a resource under construction could not reasonably be considered displaceable. It follows that any Schedule 38 analysis that includes PTC lost benefits would be invalid: either the displaced proxy resource would no longer qualify for PTCs or if the proxy resource did qualify, it would not be a displaceable unit.

- Charging Program participants for "the lost value of RECs" as part of the resource valuation calculation should be rejected by the Commission. However, if the Commission accepts RMP's proposal and requires Program participants to pay for the RECs the Agency wishes to retire, and if the Agency then *declines* to retire the RECs from the Program resource, then no "lost REC" penalty should be assessed.

- The annual update of avoided costs recommended by the Division should be rejected, as it is fundamentally incompatible with Schedule 38 method that the Division also claims to support for the purpose of valuing the program resource.

II. RESOURCE VALUATION METHOD

Q. IN YOUR DIRECT TESTIMONY, YOU RAISED A NUMBER OF CONCERNS ABOUT WHETHER THE SCHEDULE 38 AVOIDED COST METHOD PROPOSED BY RMP FOR RESOURCE VALUATION WOULD BE PROPERLY UPDATED TO REFLECT CERTAIN CRITICAL CHANGES IN THE PRICING LANDSCAPE, SUCH AS MAJOR CHANGES TO FEDERAL TAX LAW CONCERNING PRODUCTION TAX CREDITS. DO ANY OTHER WITNESSES SHARE YOUR CONCERNS?

A. Yes. WRA witness Boothman addresses this subject at length and concludes that the Schedule 38 method is not appropriate for valuation of the Program resource. Instead, Mr. Boothman recommends that the PVRR(d) method, which RMP uses to evaluate (and justify) its own resource investment decisions, should be used for this purpose. In his testimony, Mr. Boothman discusses some of the subtle differences between the two approaches.

Q. WHAT IS YOUR REACTION TO MR. BOOTHMAN'S TESTIMONY ON THIS SUBJECT?

A. Mr. Boothman provides a robust and detailed criticism of the 2025 IRP process and results, which have important implications for the use of the Schedule 38 method for resource valuation, as that method relies heavily on the IRP results. His analysis underscores the misgivings I expressed in my direct testimony regarding whether the Schedule 38 method would provide an accurate and reasonable valuation for the Program resource, given the state of the 2025 IRP and, in particular, its disconnection to current Federal tax law.

Q. DO YOU HAVE AN OPINION REGARDING THE APPROPRIATENESS OF USING THE PVRR(d) METHOD FOR VALUING THE PROGRAM RESOURCE AS MR. BOOTHMAN RECOMMENDS?

A. Yes. If the use of the Schedule 38 method for Program resource valuation turns out to be driven by meritless assumptions – which may very well be the case – then I agree with Mr. Boothman that the PVRR(d) method should be used in its stead. In fact, at an earlier stage of my work for the Agency, I anticipated that the PVRR(d) method would be the basis for the Program resource valuation and concluded it would be an acceptable approach. However, I have kept an open mind about using the Schedule 38 method, so long as the concerns I am raising are adequately addressed.

Q. HAVE THERE BEEN ANY DEVELOPMENTS SINCE YOU FILED YOUR DIRECT TESTIMONY THAT INCREASE YOUR CONCERNS REGARDING HOW THE SCHEDULE 38 METHOD MIGHT BE APPLIED?

A. Yes. On September 30, 2025, RMP filed its Q2 avoided cost compliance filing in Docket No. 03-035-14. That filing presents alternative avoided cost pricing based on two versions of the 2025 IRP, the so-called "2025 Utah IRP" and the "Final 2025 IRP."[1] According to the 2025 Utah IRP, the next displaceable proxy solar resource is the Willamette Valley, Oregon plant that is referenced in my direct testimony. Consistent with the Schedule 38 method, this plant would be displaced in 2032.[2] However, according to the Final 2025 IRP, the next displaceable proxy solar resource is a plant located at Naughton, Wyoming

[1] *Rocky Mountain Power's Quarterly Compliance Filing – 2025.Q2 Avoided Cost Input Changes*, Docket Nos. 03-034-14 & 25-035-30 (filed September 30, 2025) at 2.
[2] *Id.* at 4.

that would be displaced in 2031.[3] Notably, the 15-year levelized avoided cost for a solar tracking resource drops from $25.51/MWh using the 2025 Utah IRP[4] to the absurdly low rate of just $3.84/MWh using the Final 2025 IRP[5] for the period 2026-2041, despite avoided energy costs being a multiple of this amount.

For the purposes of this case, it is critical that the Commission be aware that in both versions of the IRP, the Willamette Valley and Naughton solar plants are each assumed to be eligible for PTCs. As I explained in my direct testimony, in accordance with the Schedule 38 calculation method, if a QF project (or Program resource) displaces a future resource that would have generated PTCs, the displacement of those future PTCs counts as a *lost benefit* in the calculation of the QF's avoided cost. That is, displacing PTCs materially reduces the avoided cost price that is offered to the QF.

Yet, the assumption that either the Willamette Valley or Naughton solar plants would be eligible for PTCs is no longer reasonable. Under recent changes in the law, to be eligible for PTCs these projects would have to have started construction prior to September 2, 2025 or have started construction prior to July 4, 2026 sufficient to meet the Physical Work Test for PTCs as described in Treasury Department Notice 2025-42 *and* be in service by December 30, 2030. Unless these projects meet these requirements, any Schedule 38 avoided cost calculations that include PTC lost benefits for these projects would be meritless.

[3] *Id.*
[4] *Id*. Appendix B.1.
[5] *Id*. Appendix D.1.

Q. HAS RMP INDICATED WHETHER THE WILLAMETTE VALLEY OR NAUGHTON SOLAR PLANTS WILL MEET THE NEW ELIGIBILITY CRITERIA FOR PTCS?

A. RMP admits in discovery that neither of these proxy resources are expected to meet the new eligibility criteria for PTCs.[6] Therefore, any attempt by RMP to value the Program resource using the PTC assumptions embedded in either the 2025 Utah IRP or the Final 2025 IRP would be entirely without merit and should be rejected by the Commission.

Q. WHAT IF, BY CHANCE, ANOTHER PACIFICORP PROXY SOLAR PLANT CAN MEET THE PTC ELIGIBILITY CRITERIA?

A. To meet the eligibility criteria, *the proxy resource would have to be under construction (physical work of a significant nature) by July 4, 2026, which is just a few months from now. By definition, a resource under construction could not reasonably be considered displaceable*. It follows that any Schedule 38 analysis that includes PTC lost benefits would be invalid: either the displaced proxy resource would no longer qualify for PTCs or if the proxy resource did qualify, it would not be a displaceable unit.

III. <u>TREATMENT OF RENEWABLE ENERGY CERTIFICATES IN VALUING THE PROGRAM RESOURCE</u>

Q. BY WAY OF BACKGROUND, WHAT IS A RENEWABLE ENERGY CERTIFICATE?

[6] *See* RMP's Response to CREA Data Request 5.1, which is included in Agency Exhibit 6.1.

A. A REC is a tradable certificate representing proof that 1 megawatt-hour of electricity was generated by an eligible renewable resource.[7] RECs generally correspond to the non-energy environmental attributes of the power generated by such resources. Once produced, RECs can be sold or transferred, retired, or banked for later disposition.

Q. DO ANY OTHER WITNESSES SUPPORT RMP'S CONTENTION THAT IN VALUING THE PROGRAM RESOURCE, PROGRAM PARTICIPANTS SHOULD PURCHASE THE "LOST VALUE OF RECS" FROM NON-PARTICIPANTS?

A. Yes. Both Division witness Lenell and OCS witness Sandonato support this position. Mr. Lenell maintains that the value of RECs should be subtracted from Program benefits as part of the resource valuation process because non-participants do not benefit from the RECs produced by the Program resource.[8] OCS witness Sandonato adopts a similar position, arguing that since non-participating ratepayers are committed to paying avoided costs for these resources they have an interest in the value of the RECs generated by the resources.[9]

Q. WHAT IS YOUR REACTION TO THESE ARGUMENTS?

A. The premise of these arguments is that by advancing the development of the Program resource, the Agency is somehow depriving non-participants of a future REC benefit. This "REC benefit deprivation" is assumed to occur because absent the program resource, RMP supposedly would have acquired a similar resource at a later date that would have produced RECs that may have been sold, producing revenue for customers. Therefore, it is argued,

[7] RMP typically refers to RECs as "Renewable Energy *Credits*" rather than "Renewable Energy *Certificates*."
[8] Direct Testimony of Timothy M. Lenell, lines 446-452.
[9] Direct Testimony of Anthony Sandonato, lines 557-582.

Program participants must compensate non-participants for the value of the future RECs that would have been produced by the proxy RMP resource that does not get built.

Notably, the "REC benefit deprivation" argument is being uniquely applied to this Program and its generation resources, as distinct from all other REC-producing generation assets that have been discretely acquired on behalf of specific Utah customers heretofore. For example, the Clean Energy Resources that are acquired to serve Schedule 32 customers are not presumed to deprive non-Schedule 32 customers of future RECs, even though the RECs produced by Schedule 32 resources are not retained by RMP.[10] Unlike what is proposed for the Program in this case, there is no "lost REC" penalty attached to Schedule 32 rates, as admitted by RMP in discovery.[11]

Similarly, the renewable resources that are acquired to serve Schedule 34 customers are not presumed to deprive non-Schedule 34 customers of future RECs, even though the RECs produced by Schedule 34 resources are retired on behalf of the Schedule 34 customer.[12] The Schedule 34 tariff prescribes credits to Schedule 34 customers for excess sales based on Schedule 37 avoided costs, which does not include a "lost REC" penalty. The tariff also provides that the Schedule 34 rate credit is based on the utility's avoided costs as defined in the Utah Annotated Code § 54-2-1(1), which states that:

> "Avoided costs" means the incremental costs to an electrical corporation of electric energy or capacity or both that, due to the purchase of electric energy or capacity or both from small power production or cogeneration facilities, the electrical

[10] "The right to any environmental attribute associated with a Clean Energy Facility shall remain the property of the Clean Energy Facility's owner, except to the extent that a contract to which the owner is a party provides otherwise." Schedule 32, Section I.C.4

[11] *See* RMP's Response to CREA Data Request 5.2.a, which is included in Agency Exhibit 6.1.

[12] "Renewable energy credits (RECs) associated with clean energy delivered under this Schedule will be deposited into an account maintained by or on behalf of the Customer, and will be retired." Schedule 34, Condition of Service 4.b.

> corporation would not have to generate itself or purchase from another electrical corporation.

This definition refers explicitly to the incremental costs of *energy* and/or *capacity*, without reference to environmental attributes, such as "lost REC" revenues. While RMP asserts that language in the tariff allowing the Schedule 34 rate to be determined by a "different methodology recommended by the qualified utility" *could* provide for the lost value of RECs to be reflected in the rate, the Company offers no evidence that any Schedule 34 contract rate has ever been designed to include such a provision.[13]

Further, RMP's Subscriber Solar program, implemented through Schedule 73, allows participants to be credited with retiring RECs,[14] also without a "lost REC" penalty, as admitted by RMP.[15]

The absence of a "lost REC" penalty from these other Utah rates is logically sound. As noted in my direct testimony and the direct testimonies of Sierra Club witness Fulmer and WRA witness Boothman, PacifiCorp does not assign a REC value to renewable resources that may be selected in its IRP, meaning that when REC-eligible resources are selected they are not assumed to generate any REC sales revenue. Nor are REC values attributed to renewable energy projects in the net benefits analysis that the Company conducts for its own projects when they are brought into rate base in a general rate case. REC values are also not accounted for in determining EBA costs and there is no "lost REC" penalty assumed when the Company curtails a solar or wind plant in making system

[13] *See* RMP's Response to CREA Data Request 5.2.b, which is included in Agency Exhibit 6.1.
[14] "The Company will retain ownership of the Renewable Energy Credits (RECs) and all other environmental attributes including but not limited to carbon emission reduction credits, which will be retired by the Company on behalf of subscribers. Customers may request to have RECs deposited in their own Western Renewable Energy Generation Information System account at their own expense." Schedule 73, Special Condition 9.
[15] *See* RMP's Response to CREA Data Request 5.2.d, which is included in Agency Exhibit 6.1.

dispatch decisions. As the valuation of RECs is not part of the standard practice of resource valuation in Utah, it is entirely reasonable that a "lost REC" penalty is not imposed on Schedule 32, 34 and 73 customers. Consistent with the ratemaking treatment for these other Utah customers acquiring renewable generation, Program participants should not be subject to a discriminatory "lost REC" penalty either.

Q. DO OTHER WITNESSES MAKE ADDITIONAL ARGUMENTS IN OPPOSITION TO REQUIRING PROGRAM PARTICPANTS TO PAY FOR THE "LOST VALUE OF RECS"?

A. Yes. WRA witness Boothman summarizes the lost REC penalty as a "nonsense proposal based on tenuous assumptions..."[16] Sierra Club witness Fulmer correctly points out that RMP has provided no reasonable way to quantify the so-called "lost value of RECs."[17] Mr. Lenell also criticizes the lack of specificity in the Company's proposal. [18] Mr. Fulmer also questions the validity of assuming a robust market for RECs will even exist.[19]

With regard to this latter point, it is important to bear in mind that [redacted] there is no plausible evidence that the incremental REC production from a displaced proxy resource would have

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[16] Direct Testimony of Karl Boothman, lines 329-330.
[17] Direct Testimony of Mark Fullmer, lines 217-242
[18] Direct Testimony of Timothy M. Lenell, lines 462-473.
[19] Direct Testimony of Mark Fullmer, lines 245-258.
[20] CONFIDENTIAL RMP Response to CREA 1.8, CONF Attachments CREA 1.8-1 and CREA 1.8-2, which are provided in CONFIDENTIAL Agency Exhibit 6.2.

resulted in a material increase in REC sales or revenue. Thus, there is no reasonable basis in evidence for saddling Program participants with a "lost REC" penalty.

Q. IN YOUR DIRECT TESTIMONY, YOU RECOMMENDED THAT IF THE COMMISSION DECIDES TO REQUIRE PROGRAM PARTICIPANTS TO PAY FOR THE "LOST VALUE" OF RECS, THE AGENCY SHOULD HAVE THE OPTION OF DECLINING TO RETIRE THEM. HOW HAVE OTHER PARTIES REACTED TO YOUR PROPOSAL?

A. The Division opposes the Agency having the right to decline to retire the RECs.[21] The OCS appears to take a similar position.[22] And while the Sierra Club agrees with me that Program participants should not be charged a lost REC penalty, Mr. Fulmer objects to the Agency being able to decline to retire the RECs.[23] On the other hand, WRA witness Boothman states that while it is not his preferred option, he agrees that "if the Commission finds that customers participating in the Program resource are obligated to compensate the Company for RECs, the Program should have the option of not retiring RECs on behalf of the Program and instead turn them over to the system, thereby eliminating the 'lost value of RECs.'"[24]

Q. WHAT IS YOUR RESPONSE TO THE DIVISION'S POSITION?

A. In the hypothetical scenario in which the IRP attributes a value to RECs and it could be shown that the displacement of a proxy renewable resource results in lost REC sales

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[21] Direct Testimony of Timothy M. Lenell, lines 439-445.
[22] Direct Testimony of Anthony Sandonato, lines 538-582. I note that Mr. Sandonato misstates my direct testimony. Contrary to his characterization, I do not agree that "if the Agency decides to retire the RECs…the Participants should be charged for the lost value of RECs."
[23] Direct Testimony of Mark Fulmer, lines 265-281.
[24] Direct Testimony of Karl G. Boothman, lines 358-362.

revenues, if the Agency were to direct that some or all of the Program resource RECs be transferred to the Company, then this would satisfy the requirement that the Program not shift costs to non-participating customers. By insisting that the Program participants pay a "lost REC" penalty, while simultaneously opposing the ability of the Agency the right to decline to retire the RECs, the Division's advocacy would force the Agency between a rock and a hard place. As it is, the Agency anticipates that Program participants will pay a premium for the Program resource. Compounding this premium with a speculative and – in my opinion, unjust – "lost REC" penalty will unnecessarily challenge the economic viability of the Program. If the cost to the Agency of retiring the RECs is to bear the burden of a contrived economic penalty, then the Agency will need to consider whether the Program is worth pursuing at all.

And while it is clearly the Agency's preference to retire the RECs, if having to compensate non-participants for lost REC revenues makes the Program economically non-viable, the Agency should be free to exercise its right to decline to retire some or all of the RECs. And if the Agency declines to retire the RECs, that is, if the Agency "donates" them back to the system at large, the Commission would have no reasonable basis to charge the Program participants a REC penalty.

Q. DOES THE AGENCY HAVE THE RIGHT TO DECLINE TO RETIRE THE RECS?

A. Although I am not an attorney, I believe the answer is clearly yes. Neither the Community Renewable Energy Act nor the Commission rules adopted to implement the Act obligate the Program to achieve a 100% clean electricity standard. Most (but not all) of the communities within the Agency have 100% clean electricity goals. This Commission is not tasked with enforcing those goals. This Commission has the authority to implement the Program as described in the Act, and the Act does not obligate the Program to achieve – or even to seek – a 100% clean electricity standard.

Second, the Act does not obligate the communities that establish the Program to have a 100% clean electricity goal. As it was originally passed, the Community Renewable Energy Act contained a provision requiring the communities seeking to create the Program to "adopt a resolution no later than December 31, 2019, that states a goal of achieving an amount equivalent to 100% of the annual electric energy supply for participating customers from a renewable energy resource by 2030."[25] This requirement was eliminated by the Utah Legislature in the 2024 General Session and is no longer a prerequisite for community participation in the Program.[26] The Act contains no reference to 100% clean or renewable energy. Consistent with the change in the Act, at least one community that did not satisfy the previous resolution requirement, Midvale, has joined the Utah renewable communities by signing the Governance Agreement.

Third, it should also be noted that the communities responsible for the Program are distinct from the customers that will participate in it. While the communities may have particular goals, the individual customers may or may not share those goals. Customers that participate in the Program will do so for their own reasons, which may not precisely align with the goals of the communities that have participated in the development of the Program. The Act does not assign a 100% clean electricity goal to customers that elect to

[25] Utah Code Ann. § 54-17-903(2)(a) (2019).
[26] *See* S.B. 214 ("Community Renewable Energy Amendments"); H.B. 241 ("Clean Energy Amendments"). The Sierra Club's witness, Mr. Fulmer, cites this removed provision in support of his argument that the Program should be obligated to retire RECs. *See* Direct Testimony of Mark Fulmer at p. 13 & FN 20.

participate in the Program and the Commission should not impose on the customers any assumptions about the purpose of the Program that are not set forth in the Act.

Fourth, neither the Act nor the Commission rules adopted to implement the Act make reference to RECs or other environmental attributes of resources acquired for the Program. The Act defines the term "clean energy resource" to mean "electric energy" that is generated by certain resource types, including wind, solar, geothermal and hydroelectric resources, as well as "energy derived from nuclear fuel."[27] The definition does not expressly include the environmental attributes of these resources.[28] Moreover, the inclusion of nuclear-fueled resources, which do not generate RECs, suggests to me that REC generation and subsequent retirement on behalf of Program participants is not fundamental to the Program as certain parties have claimed. If the laws and policies that support the creation and tracking of RECs suddenly disappeared, the Program could still exist to allow the acquisition of clean energy resources on behalf of the participating customers.

Q. IF ACHIEVING A 100% CLEAN ELECTRICITY STANDARD IS NOT AN OBLIGATION OF THE PROGRAM, THEN WHAT CAN THE PROGRAM ACCOMPLISH?

A. At a minimum, the Program will accelerate the adoption of clean electricity resources within RMP's portfolio of generation resources faster than would otherwise occur. Such an acceleration would occur if the Program resource displaces a future renewable resource.

[27] Utah Code § 54-17-902(3).

[28] The term "clean electric energy supply," defined at Utah Code § 54-17-902(2), references annual consumption for participating customers and sounds like a term that could be used to impose some sort of clean energy standard, but this defined term is not used anywhere else in the Act or in the Commission Rules implementing the Act and, therefore, imposes no particular requirements.

As I noted previously in my direct testimony, according to the current Schedule 38 calculation, the next displaceable resource for a solar tracking project is a proxy solar plant located in Willamette Valley, Oregon that would be displaced in 2032. Based on this planning assumption, if a Program resource came on line at the beginning of 2028, and it was deemed to displace this proxy plant, then, at a minimum, the Program resource would accelerate the generation of clean energy resources by four years.

In addition, however, from the perspective of clean energy advocacy, the Program may accomplish more than just *acceleration* of clean energy resources in Utah. The proxy plants identified for potential displacement in the Company's IRP are mere planning assumptions. History shows that the composition of the preferred portfolios that emerge from PacifiCorp's IRP process can change radically from planning period to planning period. Even if QFs were not developed or the Program resource was not built, there is no great assurance that the proxy renewable resources identified in the Company's IRP would actually get built. Consider that PacifiCorp is a capital-constrained utility that in 2023 suspended, then, in 2024, cancelled its 2022 All Source Request for Proposals for generation resources. As I pointed out in my direct testimony, recent changes in Federal law regarding the applicability of PTCs further erode the confidence one can place in the Company's planning assumptions, the shortcomings of which are critiqued in detail by WRA witness Boothman.[29]

For communities interested in pursuing clean energy goals, taking action now could very well mean acquiring a Program resource that does *not displace* a system renewable

[29] Direct Testimony of Karl G. Boothman, lines 177-291.

resource, but rather is entirely *additive*, because it is not clear the Company would actually acquire another renewable resource to serve Utah customers during the planning horizon – irrespective of what appears in today's preferred portfolio. From the Agency's perspective, developing a Program resource acts as a hedge against the real possibility that the proxy renewable resources in the Company's preferred portfolio would not actually be built under any circumstances. In the context of the REC discussion, making a real impact on the development of renewable resources in the State is arguably more important than getting credit for retiring the RECs.

Q. TURNING BACK TO THE QUESTION OF THE AGENCY POTENTIALLY DECIDING NOT TO RETIRE THE RECS, CAN YOU EXPAND UPON HOW THAT MIGHT WORK IN THE CONTEXT OF THE VALUATION OF THE PROGRAM RESOURCE?

A. Yes. As I've discussed already, if the resource valuation method adopted by the Commission requires the Agency to pay a "lost REC" penalty, then I recommend that the Agency be permitted to notify the Commission that it is declining to retire some or all of the RECs, effectively "turning them back" to the system. Upon such notification, the resource valuation should be restated with the "lost REC" penalty removed from the RECs that are turned back to the system.

Q. WHEN SHOULD SUCH A NOTIFICATION OCCUR?

A. The Agency should not be required to provide such notification until after the amount of the authorized "lost REC" penalty is disclosed to the Agency as part of the Program resource valuation. Under the resource valuation approach proposed by RMP, the avoided energy and capital costs would be locked down as of the execution date of power purchase agreement for the Program resource, but unlike QF pricing, would not be levelized. That is, RMP proposes that the Program resource's avoided costs as reflected in the Schedule 100 rate would change from year to year. Consistent with this general approach, I would expect that the REC valuations (as uncertain as they are) would also be locked down in advance. And to be consistent with RMP's proposal *not* to levelize the Program resource benefits, the "lost REC" penalty should not be levelized either; it should not kick in until the year in which the proxy resource that is the source of the "lost RECs revenue" would have gone into service (but for the Program resource). For example, if the displaced proxy resource was intended to go into service in 2032, the Agency should be able to choose whether to retire or turn back RECs associated with the displaced proxy resource sometime before 2032.

Alternatively, and somewhat problematically, the Division proposes that the resource valuation should be updated annually,[30] a subject that I will address later in my rebuttal testimony. If the resource valuation is updated annually, then the "lost REC" valuations would not be known until shortly before each year of the assumed displacement of the proxy resource, *e.g.*, 2032, 2033, etc. In such a scenario, *i.e.*, annual restatement of the value of the Program resource, the Agency should be permitted to decide each year whether it wished to retire the RECs or turn them back.

Q. WHY SHOULD THE AGENCY NOT BE REQUIRED TO PROVIDE NOTIFICATION BEFORE THE AMOUNT OF THE AUTHORIZED "LOST REC" PENALTY IS DISCLOSED?

[30] Direct Testimony of Timothy M. Lenell, lines 587-609.

A. Obviously, the size of any "lost REC" penalty is a critical factor in determining the economic viability of developing the Program resource. Since, all things being equal, the Agency would *prefer* to retire the RECs, it is only fair for the Agency to be informed of the magnitude of any "lost REC" penalty before making the decision either to retire them or turn them back to the rest of the system. Under the resource valuation approach proposed by RMP, where the "lost REC" penalty presumably would be locked down at the outset of the power purchase agreement, a decision by the Agency not to retire the RECs could be a one-time decision applicable to the life of the asset. Under the annual valuation recommended by the Division, it would be reasonable for the Agency to make an election whether or not to retire the RECs in response to each annual valuation.

Q. IN YOUR DIRECT TESTIMONY, YOU RECOMMENDED THAT IF THE COMMISSION REQUIRES THAT PROGRAM PARTICIPANTS PAY A "LOST REC REVENUE" PENALTY, AND THE AGENCY DECLINES TO RETIRE THE RECS, THEN THE PARTICIPANTS SHOULD BE COMPENSATED FOR THE RECS PRODUCED BY THE PROGRAM RESOURCE IN THE YEARS PRECEDING THE ASSUMED DISPLACEMENT OF THE PROXY RESOURCE. ARE THERE ANY OTHER VARIATIONS ON THIS APPROACH THAT YOU WOULD LIKE THE COMMISSION TO CONSIDER?

A. Yes. While compensating the participating customers for the REC revenues that otherwise would have been produced by the displaced proxy resource prior to the displacement of the proxy resource would be symmetrical and fair, I will also offer a hybrid approach for the Commission's consideration. Under the hybrid approach, the Agency would opt to retire the RECs for those years in which it was not subject to a "lost REC" penalty. Based on the current Schedule 38 parameters, the Agency would retire the RECs from the online date of the Program resource through the end of 2031. For the years in which a "lost REC" penalty would apply, *e.g.*, starting in 2032, the Agency would decide whether to retire or turn back some or all of the RECs after considering the economics of the "lost REC" penalty, as I discussed above. The hybrid approach would be comparable to what occurs for a QF pursuant to Schedule 38. That is, a Utah QF retains the RECs when it is compensated on an energy-only basis, but does not retain them starting in the year in which it is assumed to displace a proxy resource. While I strongly recommend that the Commission reject the imposition of a "lost REC" penalty on Program participants, if one is imposed nonetheless, the Agency should not be treated more disadvantageously than a QF.

IV. ANNUAL RESTATEMENT OF AVOIDED COSTS

Q. YOU DESCRIBED THE DIVISION'S PROPOSAL TO UPDATE THE RESOURCE VALUATION EVERY YEAR AS PROBLEMATIC. WHY IS THAT?

A. The annual update of avoided costs that the Division recommends is fundamentally incompatible with Schedule 38 method that the Division also claims to support for the purpose of valuing the Program resource. By design, the Schedule 38 method evaluates <u>long-term</u> avoided costs, including the identification of partially displaceable resources. Mr. Lenell's recommendation that "the annual Program rate setting should incorporate the most recent Schedule 38 valuation" fails to consider that the partially displaceable resource would also likely change with such an update. If the Schedule 38 method is used, it is essential that the displaceable resource used for setting avoided capital cost gets locked down and attributed to the resource that is presumed to displace it at the outset of the legally enforceable obligation enabling the development of the Program resource. The displaceable resource cannot be a "moving target" that changes from year to year for a project under contract (be it a QF or Program resource) – otherwise the Schedule 38 method is rendered meaningless. Indeed, if the Schedule 38 valuation is reset every year, the Program resource will never get credit for displacing a proxy resource due to the lead time required for resource displacement. The "displaceable" proxy resource would become an unattainable target that is moved further and further into the future with each successive reset of the Schedule 38 avoided cost.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION REGARDING THE DIVISION'S PROPOSAL TO UPDATE THE RESOURCE VALUATION EVERY YEAR?

A. If the Schedule 38 method is adopted for resource valuation, then the Division's proposal to reset avoided cost each year should be rejected as being fundamentally incompatible with that method, which requires assumptions regarding the displacement of proxy resources in specific years. Theoretically, an annual reset of avoided cost could be implemented if the avoided cost were determined by an entirely different method, such as attributing a market value to the Program resource's capacity combined with an annually determined avoided energy value. However, the fluctuating resource valuation that would accompany such an approach would suffer from the distinct disadvantage of injecting significant economic uncertainty into the decision to proceed with the development of a Program resource. Notably, prudent Company investments are not subject to such uncertainty with respect to cost recovery – nor are QF projects, for that matter. The Program resource should not be singled out for distinctly disadvantageous development terms under the guise of preventing cost shifting.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.