Rocky Mountain Power
Docket No. 25-035-06
Witness: Daniel J. MacNeil

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Surrebuttal Testimony of Daniel J. MacNeil

December 2025

Q. Are you the same Daniel J. MacNeil who previously provided direct and rebuttal testimony in this docket on behalf of PacifiCorp, d/b/a Rocky Mountain Power ("RMP" or the "Company")?

A. Yes.

I. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony responds to specific testimonies provided by the Community Renewable Energy Agency ("Agency"), Division of Public Utilities ("DPU"), the Office of Consumer Services ("OCS"), Western Resource Advocates ("WRA") and Sierra Club (collectively, "Parties") regarding the resource valuation methodology for the Utah Community Clean Energy Program ("CCEP" or "Program").

II. SUMMARY OF ISSUES AND RESPONSE

Q. How is your testimony organized?

A. Parties raise a variety of issues related to resource valuation that can be broadly organized into the following categories:

- Valuation process
- Long-term valuation vs. annual valuation updates
- Levelized costs
- Program costs and benefits reconciliation

Each of these issues is addressed in a section of my testimony.

Q. Please summarize the Company's proposed valuation process.

A. The Company expects the valuation for each Program resource to be determined by the Commission, in a manner comparable to what is already employed for each qualifying

facility contract under Schedule 38. Once a Program resource has been identified by the Agency, the Company will file an application for approval of its proposed resource valuation(s) and identify the resulting incremental costs to be collected under the Program. Interested parties will then have the opportunity to file comments and responses identifying their own recommendations, and the Commission will schedule a hearing to determine and approve the ultimate result.

Q. Please summarize why the Company supports using a one-time resource valuation, rather than annual true-ups, why reconciliation of costs and benefits should primarily reflect what was known at the time Program resource valuation is approved, and why some degree of cost levelization may be appropriate.

A. The essential premise of a risk is that the outcome is not known, and a variety of risks are already inherent in the service PacifiCorp provides to customers. There are risks from any long-term resource decision, whether the decision is to procure resources or not to procure resources. At some price point, the risks from having too many available resources balance the risks from having too few available resources, such that non-participating customers would be indifferent between having a Program resource and not having it, thus meeting the Program requirements not to shift costs or benefits. To the extent risks are balanced up front as part of the determination of a one-time Program resource valuation, ongoing true-ups of every aspect of costs and benefits is unnecessary and may be inappropriate. In a comparable way, to the extent the Company would otherwise have made long-term decisions related to the long-term costs and benefits of transmission upgrades, applying that same levelization treatment to Program resource valuation can be consistent with the statutory requirements to match

costs and benefits.

III. VALUATION PROCESS

Q. Please summarize the Parties concerns related to the valuation process.

A. OCS expresses concerns about its perception of the Company's open-ended discretion to determine the resource valuation.

Q. Please summarize the valuation process the Company expects to follow for Program resources proposed by the Agency.

A. The Company's understanding of the steps to establish resource valuation and incremental costs under the Program is as follows:

- **Bid evaluation:** Agency secures offers, identifies its best candidate resources, and provides relevant modeling details to the Company.
- **Resource valuation:** Once the Company has received required modeling information, it prepares a comprehensive resource valuation, identifying the maximum contract price at which it would be reasonable to procure a candidate resource on behalf of non-participating customers, along with its justification for that valuation. The Company has estimated that this analysis would take approximately 75 days.
- **Resource selection:** The Agency reviews the resource valuation results, selects the resource(s) it wishes to move forward with under the Program, and identifies them to the Company.
- **Contract negotiation and execution:** the Company negotiates and executes the final power purchase agreement ("PPA") for the Agency identified resource with condition precedent upon regulatory approval.

- **Valuation review and approval:**
    - The Company files an application for approval of its proposed resource valuation(s) and the resulting incremental costs to be collected under the Program.
    - Interested parties file comments and responses.
    - The Commission schedules a hearing.

Q. Is the resource valuation process described above generally consistent with the current expectations of the Agency?

A. Yes.[1]

Q. Is the Company seeking open-ended authority to determine Program resource valuation?

A. No. All Program resource valuations should be subject to stakeholder review and Commission approval. The Company recommends that this review and approval occur shortly after contract execution.

Q. Are avoided cost prices determined using the Schedule 38 methodology subject to stakeholder review and Commission approval shortly after contract execution?

A. Yes. The Company must submit fully executed power purchase agreements entered as part of Schedule 38 to the Commission for approval.[2] For example, the Company has recently submitted avoided cost pricing for approval in Dockets 25-035-51, 25-035-56, and 25-035-57. The Schedule 38 methodology also forms the basis for pricing contracts under Schedule 37. While Schedule 37 contracts are not subject to Commission

[1] Rebuttal Testimony of Christopher Thomas for the Agency ("Thomas Rebuttal"), at pgs. 15-16.
[2] Schedule 38 (Qualifying Facility Procedures) Section I.B.8.g.

approval, the published rates used in those contracts are approved by the Commission. For example, the Company filed the required annual update to Schedule 37 rates on April 23, 2025, but following comments by Parties the Commission order left existing rates in place.[3]

Q. Is the Commission required to approve avoided cost prices calculated using the approved Schedule 38 methodology?

A. No. As stated within Schedule 38, "*The Commission may approve, reject or conditionally approve a power purchase agreement and may at any time make changes to this Schedule, QF pricing methods and inputs, or terms and conditions applicable to QF pricing and power purchase agreements.*"[4] To the extent that Parties (including the Company) identify concerns with the outcomes or circumstances in the particular application of the Schedule 38 methodology brought before it, the Commission must determine whether the results provided comply with the Public Utility Regulatory Policies Act of 1978 ("PURPA") customer indifference standard applicable to QFs.[5]

Q. Is the Company required to support the avoided cost prices it calculates using the approved Schedule 38 methodology?

A. No. To the extent the Company has concerns with the avoided cost prices resulting from the Schedule 38 methodology, it can raise those concerns with the Commission as part of the contract approval process.

[3] Rocky Mountain Power's Proposed Tariff Revisions to Electric Service Schedule No. 37, Avoided Cost Purchases from Qualifying Facilities, Docket No. 25-035-T03, Order (Nov. 28, 2025).
[4] Schedule 38 (Qualifying Facility Procedures) Section I.B.4.
[5] See e.g. *Rocky Mountain Power's 2019 Avoided Cost Input Changes Quarterly Compliance Filing,* Docket No. 19-035-18, Order at 5-6 (Aug. 20, 2020).

Q. Why is the Company proposing such elaborate analysis for Program resource valuation, over and above the Schedule 38 methodology?

A. There are two reasons. First, Program resources (at least those that are not QFs) are not subject to the same contractual requirements that pertain to QFs, including contract size, contract length, interconnection cost allocation, and renewable energy credit treatment. As a result, Program resources have greater uncertainties and risks than QFs. Second, the Program may not shift costs or benefits to non-participants.[6] This could be viewed as a more stringent requirement than the PURPA customer indifference standard. The additional analysis the Company has proposed is intended to reduce the uncertainty in the cost and benefits of Program resources, to better ensure that there is no shift in costs or benefits. This analysis is also consistent with what the Company would perform to justify the prudence of other long-term resource commitments it would make on behalf of customers.

Q. Does the Company's proposed analysis directly result in a single Program resource valuation that incorporates all identified risks?

A. No. Risk is a result of uncertainty. The availability of forecasted Program resource valuations covering a range of potential future conditions does not inherently identify a single valuation result – the prevailing future condition won't be known until we get there (and maybe not even then). Recognizing that, the Company's proposed filing will include all of the relevant analysis of possible future conditions along with the Company's justification of the proposed Program resource valuation based on those results. The scope of this analysis is to ensure that sufficient data is available for Parties

[6] U.C.A. § 54-17-904(4)(b); see also Utah Administrative Rules: R746-314-401(5)(b).

to express how they believe costs and benefits, along with risks, should be balanced for the proposed Program resource. As a result, the provision of significant analysis with the filing should enable the Commission to reach a determination more rapidly, which is important given the time-sensitive nature of any long-term resource decision.

IV. LONG-TERM VALUATION VS. ANNUAL TRUE-UPS

Q. Please summarize Parties' positions related to the timing of the valuation for Program resources.

A. DPU recommends that Schedule 38 avoided costs for Program resources be updated annually.[7] Annual updates to Program resource values are opposed by the Agency and Sierra Club, who instead recommend that the resource valuation and resulting incremental costs be recovered from participating customers and established at the time of contract execution.

Q. If contracted bilaterally by the Company or through an RFP, can resources result in expected net benefits for all customers?

A. Yes. When PacifiCorp conducts a Request for Proposals ("RFP"), it seeks to identify the least-cost, least-risk mix of bids to meet its requirements, complementing its existing portfolio and other resource additions in the future. While individual resources are not without risk, they can contribute to lower levels of risk in a portfolio as a whole. When the expected benefits and relative risks associated with a resource are expected to exceed the contract price and any associated transmission upgrade costs, the result is a net benefit, and the Company would enter the contract on behalf of all customers. For future analysis, the Company would then plan around the contracted resource's

[7] Rebuttal Testimony of Timothy M. Lenell for the Division ("Lenell Rebuttal"), at pg. 2.

expected output and contractual requirements, update its assumptions and estimates when better information becomes available, and generally maximize the value of that resource in order to minimize its overall revenue requirement to be collected from customers. The assumed costs, benefits, and risks at the time of contract execution are beside the point in actual operations over the life of a contract.

Q. Is there a contract price where any given resource would represent neither a benefit nor a cost?

A. Theoretically, yes. The breakeven price where costs and benefits perfectly balance would be dependent on a variety of inputs and assumptions, but it could generally be calculated for any set of inputs and assumptions.

Q. Is the precise breakeven contract price typically important in long-term resource procurement?

A. No. In an RFP or bilateral contract analysis of the breakeven concept may come up as a point of reference, but the emphasis is usually on the expected net benefits, and the yes/no decision to proceed with a long-term resource. Parties do not need to agree on the precise net benefit result (and the associated breakeven price) in order conclude that the decision to proceed with a long-term resource outweighs not proceeding with that resource.

Q. How does this breakeven concept relate to the Program and whether a one-time resource valuation may be used?

A. There are risks from any long-term resource decision, whether the decision is to procure resources or not to procure resources. At the breakeven price point, the risks from having too many available resources balance the risks from having too few available

resources, such that non-participating customers would be indifferent between having a Program resource and not having it. The Company believes this would meet the Program requirements not to shift costs or benefits. This is not to say that Program resources are without risks, but rather that those risks can be balanced out such that they are equivalent to what non-participating customers would otherwise have faced.

Q. Does the Company have concerns about DPU's proposed annual update process?

A. Yes. Creating a one-year forecast prior to each year would be burdensome for the Company, as well as for stakeholders seeking to review the results, particularly during periods when inputs and assumptions are in dispute. While the Company updates avoided costs on an annual basis for Schedule 37 and a number of non-firm QFs, these proceedings are generally not contested and the resulting prices do not apply to a significant volume of generation output each year. Even those results are not particularly accurate for non-firm QFs, which tend not to deliver consistently. The Company is considering ways to use market prices, such as the Western Energy Imbalance Market ("WEIM"), for non-firm QFs rather than a forecast, eliminating both the preparation and review of the results. Creating new annual update processes would be contrary to this goal.

Q. Has the Commission previously decided against using production cost modeling forecasts for use in annual updates?

A. Yes. As part of proceeding to determine export credit rates for customer generation, the Commission adopted an annual update process and an avoided energy cost methodology that uses historical WEIM prices, rather than relying upon production

cost modeling.[8] To the extent Program resource value is to be based on short-term values, using actual market prices is less labor-intensive and more transparent.

Q. Do market prices comprehensively identify resource value?

A. No. WEIM market prices are not considered firm, so they do not fully encompass capacity value and reliability benefits, and other market prices from the CAISO's Extended Day-Ahead Market ("EDAM") or the Intercontinental Exchange ("ICE") may only capture some aspects of capacity value, may or may not be applicable to the Company's present or expected requirements, and can be challenging to translate into a value applicable to a variable energy resource (or any resource) without the extensive use of production cost modeling forecasts.

Q. Does DPU's current proposal for annual updates to Program resource valuation sufficiently characterize the process, such that it could be administered by the Company?

A. No. If the Commission sought to determine Program resource valuation through an annual update process, the Company would recommend that additional details on the process be worked out, particularly related to the timing of the analysis and review by Parties.

V. LEVELIZED COSTS

Q. Please summarize Parties' concerns related to levelized costs.

A. DPU suggests that the Program should "avoid inter-year cross-subsidization among participating and non-participating customers."[9]

[8] *Application of Rocky Mountain Power to Establish Export Credits for Customer Generated Electricity*, Docket No. 17-035-61, Order (Oct. 30, 2020).
[9] Lenell Rebuttal, at 3.

Q. How does inter-year cross-subsidization implicate levelized costs?

A. The Company's recovery of its capital expenditures is based on its rate base and the depreciated value of its assets, which varies each year over the life of the asset. To help align costs and benefits, modeling in an IRP or RFP only includes an annualized representation of capital costs for transmission and resources, (i.e. the costs are spread over each year of an asset's expected life, including years that are beyond the horizon of the study); (e.g. 2045 was the final year analyzed in the 2025 IRP).

Q. Are there different ways to spread capital costs over the life of an asset?

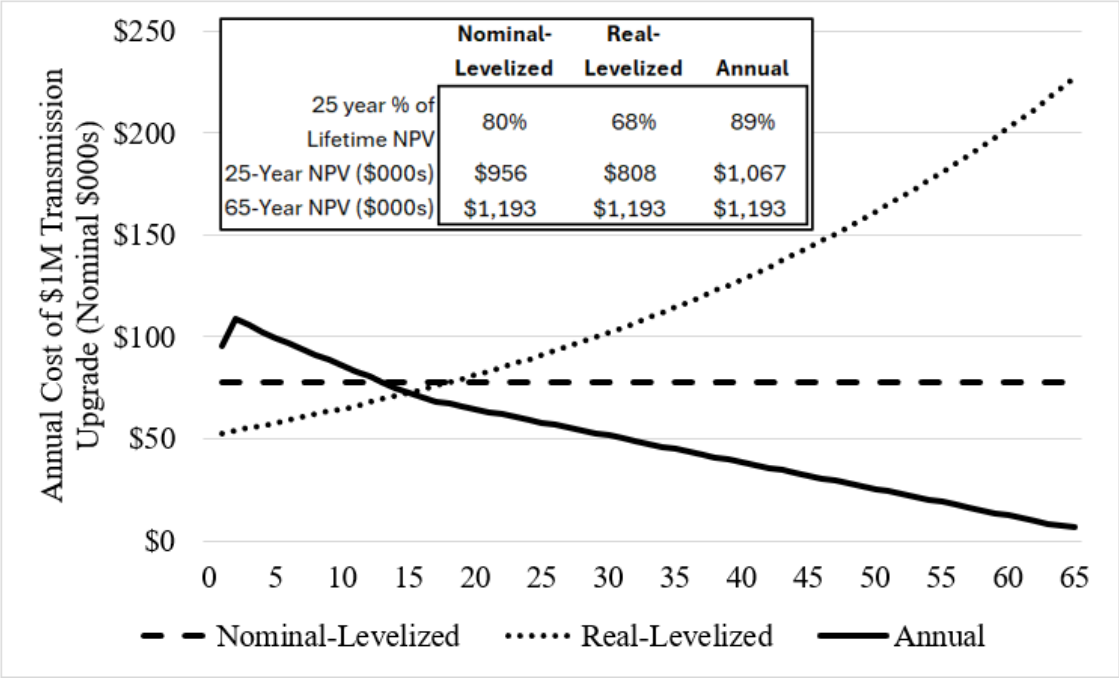
A. Yes. In the 2025 IRP, transmission upgrade costs were modeled based on real-levelized annualized capital costs. This is the proposed treatment for transmission costs I identified in my Direct testimony.[10] Real-levelized costs grow at inflation, resulting in constant dollars in real terms. This means that the same real dollar value would apply for each year of the expected 65-year life of a transmission asset.

As an alternative, nominal-levelized annualized capital costs start at a specified value and remain constant in nominal terms (i.e., the same number every year). Nominal-levelized values start out higher than real-levelized values but the inflation adjustment causes real-levelized values to exceed the nominal levelized value part way through the life of the asset. Practically speaking, nominal-levelized values capture more of the capital cost up front, even though the present-value results are identical for real-levelized and nominal-levelized costs when measured over the entire life of a given asset using a discount rate that reflects the Company's current weighted average cost of capital.

[10] Direct Testimony of Daniel J. MacNeil for Rocky Mountain Power ("MacNeil Direct"), at 5-6.

In the revenue requirement calculation used to set customer rates, the current rate base and depreciation values are used in each year. A new asset added to rate base is depreciated each year, resulting in reductions to rate base. While this depreciation is part of the revenue requirement, the reduction in rate base each year results in lower and lower revenue requirements in future years, with some complications due to taxes and other adjustments. This rate treatment results in even more capital cost being recovered up front, despite having the same present-value as the real-levelized and nominal-levelized values over the life of the asset. A comparison of the three transmission annualized cost treatments is shown in Figure 1. An inset table also shows how the present value costs compare over the expected 25-year life of a solar resource and the expected 65-year life of transmission upgrades. In the first twenty-five years, the real-levelized cost treatment collects approximately 68% of the lifetime present value transmission upgrade cost, whereas the nominal levelized cost treatment collects 80% and the annual depreciated revenue requirement collects 89%.

Figure 1: Levelized Transmission Cost Comparison



Q. How does Figure 1 relate to DPU's recommendation that the Program avoid inter-year cross-subsidization?

A. Levelized values inherently result in inter-year cross-subsidization. In IRP and RFP planning, PacifiCorp is focused on identifying the least-cost, least-risk alternatives over time, and levelization can help account for the fact that benefits are difficult to quantify outside of the study horizon. To the extent benefits continue at a comparable level, transmission upgrades that are cost-effective within the study horizon would generally continue to be cost-effective over their entire life. In an IRP, where analysis generally ceases at the end of study period (i.e. 2045 in the 2025 IRP), transmission would be evaluated relative to its costs and benefits through 2045 only. In an RFP, the analysis would capture transmission costs and benefits through the life of each resource, analogous to the 25-year value for solar resources in Figure 1.

Q. Is the Company proposing that all transmission costs be recovered in the year in which they are included in the revenue requirement but no later than the end of the Program resource contract term?

A. No. To the extent that long-term Program resource valuation is aligned with PacifiCorp's standard practices for identifying and procuring cost-effective long-term resources, the Company's proposal to account for real-levelized annualized transmission costs over the term of the contract would also produce a cost-effective result. Transmission upgrades can provide value and options in the future that cannot be readily quantified today. Major transmission upgrades are more likely to involve secondary benefits (such as incremental transfer capability, congestion relief, and increased reliability), which can be quantified and are almost certain to continue beyond the life of a Program resource. Any transmission upgrade might be a necessary component to achieve these benefits at some point in the future and might become necessary at some future date even in the absence of the Program resource. But, to the extent that this treatment of transmission costs is deemed cross-subsidization, the real-levelized transmission cost calculation proposed by PacifiCorp would need to be increased by 32 percent to produce the same net present value as the annual stream over a 25-year contract term, or by 48 percent to produce the same net present value as the annual stream over the 65-year life of a transmission asset. While this may seem like a very large impact, in many instances transmission upgrade costs represent a small portion of the overall resource cost (i.e. relative to the payments under a power purchase agreement).

VI. PROGRAM RESOURCE COSTS AND BENEFITS RECONCILIATION

Q. What aspects of Program costs and benefits reconciliation do you address in this testimony?

A. My testimony addresses the costs and benefits related to the valuation of Program resources and recovery of appropriate incremental costs over time, and not those related to Program administration or rates.

Q. Please summarize Parties' positions related to the reconciliation of the costs and benefits of Program resources over time.

A. DPU recommends that an annual reconciliation process be used to ensure that no cost shifting occurs as a result of the Program.[11] This is in conjunction with DPU's recommendation for annual updates to Program resource value, though the reconciliation could be beneficial even if Program resource value is established by the Commission at contract execution.

Q. Will the total incremental costs of Program resources vary from year to year?

A. Yes. The generation output of any resource will vary from year to year. This is particularly true for resources that are dependent on weather, like wind and solar. For Program resources procured through a power purchase agreement, changes in generation will be directly correlated with compensation to the resource owner, as the purchase price is volumetric. As a result, if a given year has more sunny days than was expected, Program resource generation and payments to the resource owner would increase. To the extent the purchase price exceeds the resource value, and all else being equal, a higher annual volume would increase the incremental cost of the resource for

[11] Lenell Rebuttal, at 2-3.

that year. Notwithstanding the impact of weather, annual output may not average out to the forecasted level over time, as the efficiency and long-term performance of the generating equipment is only an estimate.

Q. Is the Program resource purchase price volumetric based on generation?

A. Not entirely. As noted in my Direct testimony, PacifiCorp's non-QF contracts for wind and solar resources typically include compensable curtailment provisions, such that the resource owner receives the contract price, plus the value of any lost production tax credits, on any economically curtailed output.[12] Curtailment of a Program resource would avoid incurring additional costs related to negative prices in the WEIM and would reduce the quantity of renewable energy credits ("RECs") produced, but would not change the compensation to the Project owner under the power purchase agreement. To the extent compensable curtailment has occurred, reconciliation based solely on the actual generation or RECs would understate the incremental cost.

Q. Do all of the incremental costs of Program resources vary based on generation and economically curtailed output?

A. No. Transmission upgrade costs associated with a Program resource would be fixed and would not vary as a result of generation output in a given year.

Q. How would you recommend that the incremental costs of Program resources be reconciled to ensure no costs or benefits are shifted between participating and non-participating customers?

A. The Company recommends that the annual incremental cost of transmission upgrades be reconciled based on fixed annual dollar amounts over the associated Program

[12] MacNeil Direct, at 7-10.

resource's contract term. The Company recommends that the remaining portion of the annual incremental cost be reconciled based on the volume used to compensate the resource owner, (i.e. the sum of the generation and economically curtailed output). This volume would be multiplied by the incremental cost for that year (in dollars per megawatt-hour) that was approved by the Commission.

Q. How would this proposal differ from a reconciliation based solely on an incremental cost applied to the number of RECs generated and delivered by the Program Resource?

A. This proposal ensures incremental costs are captured accurately for transmission upgrades and for any compensable curtailment that occurs at a Program resource. If the actual generation matches the expected volume and there is no compensable curtailment, the Company's proposal would be identical to an incremental cost applied to RECs in both respects. However, if actual generation is lower than expected, the Company's proposal will continue to account for the entire incremental transmission upgrade cost, whereas a REC-based incremental cost would account for a reduced portion of the total. This adjustment is symmetrical, as the Company's proposal would avoid over-collecting for incremental transmission upgrade costs when actual generation exceeds the expected volume.

Calculating the actual incremental cost in a year based on the sum of generation and curtailed volume will result in a higher total amount than generation alone; however, it is appropriate to calculate the volumetric rate in the same way using both generation and curtailed volume in the divisor, potentially resulting in a lower volumetric rate and an equivalent annual incremental cost all things being equal. When

actual curtailment is higher than expected, a larger portion of the payments to the resource developer would be based on curtailed volume, rather than generated volume. It is appropriate for the incremental cost reconciliation to capture those additional payments. Under a REC-based incremental cost, every time curtailment occurred the incremental costs assigned to the Program would be reduced, and non-participating customers would be responsible for the entirety of the contract price paid to the resource owner for that period.

Q. Should actual transmission upgrade costs be used in the reconciliation process?

A. No. The decision to execute a long-term contract or procure any resource will never be based on perfect knowledge of all future transmission costs. Circumstances routinely change and besides evaluating risks and making choices using the best information available, there is little the Company can do to control these outcomes. As such, this type of risk is necessarily a part of long-term resource planning and procurement. Once necessary Commission approvals are received, and any transmission-service request studies come back without excessive costs or delays, PacifiCorp's proforma power purchase agreements used in RFPs would no longer give the Company the right to terminate or seek redress from the seller for changes in transmission upgrade costs. Retaining such a right in the proforma power purchase agreement would result in greater risks for bidders, who would need to bid higher prices to compensate, particularly since bidders are less acquainted with the possible transmission system outcomes than the Company and would be unable to accurately evaluate the risk, necessitating an even higher bid price and resulting in greater costs for customers.

Q. Does this conclude your surrebuttal testimony?

A. Yes.