BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

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**

DIRECT TESTIMONY AND EXHIBITS OF

MARK FULMER

On Behalf of

Sierra Club

October 10, 2025

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I. INTRODUCTION

Q: Please state your name and business address.

A: My name is Mark Fulmer. My business address is 1736 Franklin Street, Suite 700, Oakland, California, 94612.

Q: By whom are you employed and what is your position there?

A: I am a Principal/Owner at MRW & Associates. I have been consulting in electricity and natural gas since 1990 (35 years).

Q: What is your educational background?

A: I hold a Bachelor of Science degree in mechanical engineering from the University of California, Irvine and a master's degree from the Department of Mechanical and Aerospace Engineering at Princeton University, where I took courses from the Woodrow Wilson School of Public Affairs and conducted research at the Center for Energy and Environmental Studies. My CV is attached as Exhibit 1.1.

Q: Have you testified before the Utah Public Service Commission or any other utility commissions?

A: This is the first time I have testified before the Utah Public Service Commission ("PSC"). I have testified numerous times before the California Public Utilities Commission as well as before commissions in Arizona, Colorado, New Mexico, Washington, Pennsylvania, Rhode Island, and the Federal Energy Regulatory Commission. This includes addressing avoided cost issues associated with renewable energy in Arizona (addressing solar buyback rates) and New Mexico (addressing replacement power for San Juan Generating Station Units 2 and 3). I have also provided testimony in California concerning community energy programs, known as Community Choice Aggregation ("CCA"), addressing the rules governing the relationship between CCAs and California inventor-owned utilities as well as the fees the CCAs and their customers must pay utilities for any generation-related stranded costs that the CCA formation might cause.

Q: On whose behalf are you testifying in this proceeding?

A: I am testifying on behalf of Sierra Club.

Q: What is the purpose of your testimony?

A: Sierra Club retained me to examine a proposal from PacifiCorp d/b/a Rocky Mountain Power ("RMP" or "Company") for a new tariff, Schedule 100, which will establish resource valuation for resources acquired in support of the Utah Community Renewable Energy Program ("Program").

Q. What documents did you review in preparing this testimony?

A. I reviewed the testimony that has previously been filed in this docket by RMP and the Community Renewable Energy Agency ("CREA" or "Agency"), the associated workpapers, and discovery produced in this case.

Q: Please summarize your conclusions and recommendations.

A: My conclusions are:

1. Schedule 38 is an appropriate starting point for valuing Schedule 100 resources and setting the associated rate.
2. Schedule 100 must ensure that the associated project is responsible for only the interconnection and transmission upgrade costs needed to allow the project to connect to the PacifiCorp transmission grid and no more.
3. The Schedule 100 project valuation should not be adjusted for any "lost value of Renewable Energy Credits ("RECs")" from a proxy renewable resource.

4. RECs generated by Schedule 100 projects should be retired and not resold or given to PacifiCorp.

5. Schedule 100 resources should not be modeled with a negative dispatch price equal to the incremental cost of Schedule 100 resources.

6. When presenting potential pricing to the Commission for approval, RMP should include a price analysis using social costs when considering the benefits of a Schedule 100 project.

7. The Commission should reject RMP's request for open-ended authority to impose additional pricing adjustments under the rubric of "other modifications." If RMP identifies what it believes to be a cost or benefit shift, it should not have the unilateral authority to impose a remedy without full Commission review and an opportunity for intervenor input.

8. Avoided cost calculations must reflect the loss of federal production tax credits ("PTCs") and other federal policy changes affecting solar costs, as these materially affect the economics of Schedule 100 projects and PacifiCorp's IRP resource selection.

II. RESOURCE VALUATION

Q: How does the value of a Schedule 100 project enter into the ultimate rate charged to Program Participants?

A: As noted by RMP witness MacNeil, Schedule 100 must reflect both the costs of Schedule 100 projects as well as the benefits that the projects provide to RMP and its ratepayers. The costs are relatively straightforward: the cost associated with the renewable power purchase agreement ("PPA") RMP enters into with a renewable generator on behalf of the

CREA, plus project administration that RMP incidentally incurs, plus project interconnection costs, plus a fraction of any required transmission upgrades. The benefits include the deferred capital costs and avoided generation and capacity costs that RMP would have otherwise had to incur (i.e., the avoided costs).

Q: How does RMP propose valuing Schedule 100 projects?

A: Per the testimony of witness MacNeil, RMP proposes to estimate the value of a Schedule 100 resource using the methodology for Electric Service Schedule Number 38 ("Schedule 38"), which defines the value of large qualifying facilities ("QFs") underlying the payments to those QFs.[1] From that Schedule 38-based estimate, RMP proposes adjustments to account for (1) the impact of transmission upgrade costs associated with the proposed Schedule 100 resource; (2) the costs and benefits of the project's contract term beyond the production cost model study horizon; (3) the value of RECs that would have been generated by the proxy resource; and (4) "any price-policy, risk, or other modifications it believes are appropriate to ensure the Schedule 100 resource value does not shift any costs or benefits to non-participating customers."[2]

Q: Is Schedule 38 a reasonable starting point for valuing the benefits of a Schedule 100 project?

A: In general, yes. Schedule 38 applies to QFs with design capacities greater than 1,000 kW (Cogeneration Facility) or 3,000 kW (Small Power Production facility). Given that the anticipated solar projects that will be acquired by RMP as part of the Schedule 100 process, this is a reasonable starting point. Nonetheless, as I discuss below, there are areas

[1] Direct Testimony of Daniel J. MacNeil at 2:30-40, 3:57-4:70 [hereinafter "MacNeil"].
[2] *Id*. at 2:36-38, 4.

where the Commission must be careful to ensure that the valuations are appropriate for the differences between the Schedule 100 situations and that for a Schedule 38 QF.

III. TRANSMISSION UPGRADE AND INTERCONNECTION COSTS

Q: What are the issues with transmission interconnection and upgrade costs?

A: The recovery of costs associated with interconnecting project and necessary transmission upgrades are clear if the generating project is a QF or if the generating project is owned by RMP. However, the Schedule 100 renewable generating projects are a hybrid: they are treated like a QF for avoided energy and capacity valuation purposes, and like non-QF PPAs for interconnection and transmission upgrade cost purposes.

Q: How are transmission interconnection and upgrade costs treated for Schedule 38 QFs and for RMP contracted generators?

A: As witness MacNeil explains, the cost to interconnect the QF to the PacifiCorp transmission system as well as any upgrades to the transmission system that PacifiCorp finds necessary are paid for by the QF's developer.[3]

For generators with whom RMP directly contracts, the interconnection and transmission system upgrade costs are initially funded by the developer, who is refunded the cost by PacifiCorp over time, with interest. PacifiCorp in turn places the refunded amount into rate base.[4] These rate-based costs are collected from retail ratepayers of PacifiCorp's affiliates' through retail rates and wholesale transmission users through PacifiCorp's Open Access Transmission Tariff ("OATT"). As noted by MacNeil,

[3] *Id*. at 4:80-82. In this section, Mr. MacNeil refers to "upgrades" associated with QFs, but not interconnection. I assume that his use of the word "upgrade" here encompasses QF interconnection, too.
[4] *Id*. at 4:83-88.

currently 80 percent of the costs flow to retail customers while 20 percent flow to wholesale transmission uses via the OATT.[5]

Q: How does RMP's propose transmission interconnection and upgrade costs be treated for Schedule 100 projects?

A: RMP proposes to have the transmission upgrade and interconnection costs associated with Schedule 100 renewable resources treated the same it does for a non-QF project: the transmission upgrade and interconnection costs would be initially paid for by the project's developer, who would then be reimbursed by RMP retail and PacifiCorp OATT customers as the assets are placed into rate base. I assume that these up-front costs would ultimately be paid by, and eventually refunded to, the RMP retail customers who are participating in the program.

Q: Do you find this to be reasonable?

A: In general, yes, but RMP and the Commission must pay close attention to the details to ensure that costs are appropriately charged to the project so that the ratepayers served the Agency's Schedule 100 resources are not subsidizing costs that should be borne by the broader set of RMP ratepayers, and vice versa. As noted by CREA Witness Kevin C. Higgins:

> …it is important from a valuation perspective to recognize certain nuances. Specifically, since the costs incurred by the developer for interconnection Network Upgrades are subject to refund over time, RMP's modeling of the revenue requirement impacts must accurately reflect the timing of the rate base impacts. In particular, the Company would not be making the initial capital investment and therefore would not be entitled to

[5] *Id*. at 6:129-131.

earn a return on that rate base until it begins refunding the developer's capital outlay.[6]

Mr. Higgins also notes a number of cases where excess costs might be assigned to Schedule 100 projects. This includes when upgrades recommended by PacifiCorp transmission are in excess of what is needed to actually interconnect the Schedule 100 project. This might be due to (as Mr. Higgins notes) the "lumpy" nature of transmission investment, or the assumed possibility that additional generation resources will eventually be added on the same line to serve the greater PacifiCorp system and not simply the Schedule 100 ratepayers.[7]

In these cases, Hr. Higgins recommends that any excess capacity slated by PacifiCorp that "provides benefits beyond merely interconnecting the [Schedule 100] Program resource, only the proportion of generator allocated interconnection Network Upgrade costs that corresponds to the capacity needed to mitigate the generator interconnection should be factored into the valuation."[8] I concur with this, and further recommend that the costs of *any* excess capacity, even if PacifiCorp does not identify specific benefits beyond the Schedule 100 project interconnection, should not be paid for by the Schedule 100 generator but be paid for by PacifiCorp and placed into rate base like any other transmission investment. To do otherwise begs the question, why are these extra costs being incurred, and why should they be the responsibility of the Schedule 100 resource?

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[6] Direct Testimony of Kevin C. Higgins at 16:344-350 [hereinafter "Higgins"]. Mr. Higgins specifically addressed the interconnection costs, but later notes, "[t]o the extent that an identified transmission service Network Upgrade creates excess capacity beyond what is needed to deliver the generation from the Program resource to the Company's retail loads, the system benefits resulting from that excess capacity should be factored into the valuation." *Id.* at 18:400-403.
[7] *Id*. at 16:361-17:367.
[8] *Id*. at 16:363-17:367.

Q: Does Mr. Higgins make any other recommendations that you want to comment on?

A: Yes. Mr. Higgins notes:

> …if the resource valuation is conducted within the Schedule 38 analytical framework and the analysis includes a displaced resource, then the avoided interconnection costs of the *displaced resource* must be considered a benefit attributed to the Project resource.[9]

I fully concur with Mr. Higgins on this point. If a Schedule 100 project results in the deferral or displacement of another resource, the full avoided cost of the deferral or displacement, including any interconnection or transmission upgrade costs, must be credited to the Schedule 100 project.

IV. THE "LOST VALUE OF RENEWABLE ENERGY CREDITS" SHOULD NOT BE CONSIDERED

Q: Please describe RMP's position regarding "lost value of RECs."

A: In Direct Testimony, RMP witness MacNeil describes a difference between Schedule 38 and RMP's proposed Schedule 100 related to RECs.[10] Under Schedule 38, RMP retains RECs produced by QFs during the time a QF is assumed to defer a renewable resource. As an example, the Quarter 1 ("Q1") 2025 Schedule 38 compliance filing[11] shows a solar QF would defer 77.7 MW of a solar proxy resource in Willamette Valley, Oregon starting in 2032, and that RMP would retain 100% of RECs from a solar QF for the period of the deferral. Conversely, Communities participating in the Program are likely to seek to retire RECs.[12] Thus, under Schedule 100, RMP would not retain the RECs like it does with

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[9] *Id*. at 17:368-371 (emphasis in original).
[10] MacNeil at 7:142-8:157.
[11] Utah Pub. Serv. Comm'n, Dkt. No. 25-035-30, RMP's Quarterly Compliance Filing – 2025.Q1 Avoided Cost Input Changes, Appendix A at 4 (May 7, 2025), *available at* https://pscdocs.utah.gov/electric/25docs/2503530/339680RMP2025Q1AvdCstInptChngs5-7-2025.pdf.
[12] Higgins at 19:411-413.

QFs. RMP then claims it should add a “lost value of RECs” to the Schedule 100 valuation, effectively charging participating customers for avoided REC sales revenues.

Q: Does RMP provide a methodology for calculating the “lost value of RECs”?

A: No.[13]

Q: You state that RMP uses a proxy resource, currently the 77.7 MW solar generator in Oregon, for calculating the deferral value of a renewable QF. Please describe the Schedule 38 methodology for determining a proxy resource.

A: Under Schedule 38, RMP determines what proxy resources are available from its latest IRP. A proxy resource can be “deferred” by a QF, meaning the cost of that resource can be avoided by the QF, and hence the cost of the proxy resource becomes the basis of the avoided cost calculation. Put another way, a deferrable resource is one the utility would otherwise build to meet system needs, but that can be postponed if a customer brings on its own renewable project as a QF.

The use of a proxy resource also determines what entity gets the RECs. If a renewable proxy resource is identified, PacifiCorp will retain the RECs. If not, and the avoided costs of renewable QFs are based on an assumed market price instead of a proxy resource, the QF owner retains the RECs.

Q: Is RMP’s proposal to value the “lost RECs” for Schedule 100 projects reasonable?

A: No, for at least three reasons. First, renewable proxy resources used in Schedule 38 have no REC value to remove from the calculation. Second, RMP does not model resources in its Integrated Resource Plan (“IRP”) to meet Renewable Portfolio Standard (“RPS”) requirements of other entities, leaving no practical method to calculate what the “lost

[13] Ex. 1.2 (Data Request Response OCS 2.6).

value of RECs" would be. Third, RMP has presented no evidence that its total REC sales revenue would decrease if RECs from Schedule 100 resources are retired instead of marketed for sale.

A. Schedule 38 Proxy Resources Have No REC Value

Q: Why is it reasonable to use proxy resources such as the Oregon solar resource discussed earlier for Schedule 100 projects even though the proxy resource can generate RECs and Schedule 100 resources may not?

A: Although the Schedule 38 proxy resource generates RECs, these resources have no assigned REC value under the Schedule 38 valuation methodology or within the IRP modeling. This means that these renewable proxy resources are added purely as a source of economic energy and capacity to serve PacifiCorp load and not "for other possible revenue streams" such as REC sales revenues.[14] As long as such proxy resources are only used to quantify avoided energy and capacity benefits of Program resources, they could still be considered valid proxy resources. To reiterate, Schedule 38 uses its renewable proxy resources to quantify avoided energy and capacity costs of such resources, not any avoided REC costs. Therefore, using Schedule 38 proxy resources as proxy resources for Schedule 100 is reasonable, even if Schedule 100 Program resources do not generate RECs.

[14] Ex. 1.3 (Data Request Response Sierra Club 2.2).

B. RMP Has Provided No Reasonable Way to Quantify "Lost Value of RECs"

Q: Putting aside the argument regarding the validity of certain proxy resources, is it reasonable for RMP to attempt to quantify "lost value of RECs" using its IRP?

A: No. RMP does not model the load and resources external to its system in its production cost modeling, leaving no straightforward way to determine what energy is needed to meet RPS compliance requirements in other states for the purposes of quantifying REC revenues.[15] RMP has, essentially, deemed such modeling unnecessary and out-of-scope, and so it should remain out-of-scope for the purposes of Schedule 100.

Q: Does RMP address this issue in its testimony in this proceeding and provide a detailed methodology for calculating the "lost value of RECs"?

A: No. As stated earlier, RMP has not provided any such methodology.[16]

Q: What work would be required to add external regions to the modeling to generate a reasonable REC value?

A: The amount of work needed to expand modeling to include external areas and properly quantify REC revenues constitutes an enormous effort and would be subject to great uncertainty. The proposed resource valuation method involves forecasting avoided costs over the lifetime of a facility, which RMP admits is likely to be greater than the Schedule 38 fifteen-year horizon.[17] Numerous assumptions would need to be made regarding the viability of REC sales to other parties. For instance, California is a large market in the Western Electricity Coordinating Council ("WECC") region. However, currently the California Public Utilities Commission does not count unbundled REC purchases as

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[15] Ex. 1.3 (Data Request Response Sierra Club 4.2 (c)).
[16] Ex. 1.2 (Data Request Response OCS 2.6).
[17] MacNeil at 10:211-212.

greenhouse gas ("GHG")-free for its IRP process, undermining the ability of RMP's RECs to meet California's ambitious GHG reduction targets in the long-term.[18] Therefore, any attempt by RMP to try to circumvent such issues and simply extrapolate past REC sales or presume, without analysis, that a robust REC market will even exist in fifteen years let alone be modeled successfully should be rejected.

C. Retiring RECs from Program Resources May Not Decrease Total REC Sales Revenues

Q: Please explain why retiring RECs from Program resources may not decrease REC sales revenues.

A: As discussed earlier, for purposes of RMP's IRP modeling, REC sales revenues are treated as an unquantified, "possible" revenue stream, secondary to the primary purpose of serving load. The ability to generate REC revenues depends upon the vagaries of REC markets, which have varied eligibility requirements by state and complex banking rules. Ultimately, REC prices depend on the demand and supply of RECs. Because of this, it is incorrect to simply presume a robust market would exist for all the RECs generated by Program resources. It is possible that the attempt to market the RECs could result in oversupply and decrease REC prices or make it more difficult to market RECs from other RMP facilities. Moreover, nothing prevents PacifiCorp from building additional resources that can generate REC revenues in addition to the Program resources. Before any "lost

[18] Unbundled RECs are Portfolio Content Category ("PCC") 3 resources that are not eligible for inclusion in IRP emissions modeling. *See* CPUC, *Greenhouse Gas and Criteria Pollutant Accounting Methodology for Use in Load-Serving Entity Portfolio Development in 2022 Integrated Resource Plans* at A-14 (July 2022), *available at* https://www.cpuc.ca.gov/-/.media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/clean-system-power-calculator-documentation.pdf ("Generation from PCC2 and PCC3 renewables are not included in the [clean system power ("CSP")] calculator's renewable generation percentage but are eligible for RPS requirement compliance; the CSP calculator does not contain information on PCC2 and PCC3 RECs.")

value of RECs" could be quantified, PacifiCorp would need to show evidence of adequate demand for RECs in the first place, which to date, it has not done.

D. Alternatives to RMP "Lost Value of RECs" Proposal

Q: Are there alternatives to RMP's proposal for the "lost value of RECs?"

A: Yes. If the Commission chooses to reject my recommendation and allow PacifiCorp to charge program participants for the "lost value of RECs," then CREA witness Kevin Higgins proposes to allow CREA the ability to decline to retire the RECs and instead turn them over to PacifiCorp in support of the system.[19]

Q: Do you support this alternative proposal?

A: No. Allowing PacifiCorp to market RECs from the Program undermines the Program's objective of meeting 100% of participating customers' annual electric energy supply with renewable energy.[20] The goal, then, is to provide clean resources to serve RMP's Utah load and not help other jurisdictions meet RPS goals. Selling the RECs would effectively double-count the renewable attribute of the resource for both Utah under the Program and for the RPS of another state.

A more viable alternative to CREA's proposal is to instead use a different proxy resource than the currently-identified Oregon solar resource to quantify avoided energy and capacity costs, including fossil-fueled thermal resources. This would be consistent with Schedule 38 methodology, which, as indicated earlier, would allow QF owners to retain RECs during times there is not valid renewable proxy resource. It would also make

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[19] Higgins at 20:443-21:446.

[20] Utah Code § 54-17-902(3) (describing the "community clean energy program" as a program approved by the Commission allowing a qualified utility to provide electric service from one or more renewable energy resources to participating customers within participating communities); *Id.* § 54-17-903(2)(a) (requiring participating communities to adopt resolutions with stated goals of achieving an amount equivalent to 100% of the annual electric energy supply for participating customers from a renewable energy resource by 2030).

sense given the intent of the program to add more clean resources to the system and displace fossil resources. If the Program resources simply substitute for similar clean resources, like the Oregon solar proxy, it is not clear why PacifiCorp is not simply building the Program resources in the first instance without the need to charge Program participants any additional costs.

E. "REC Price" Impacts on Production Cost Modeling

Q: Are there any other issues related to RECs?

A: Yes. RMP witness Daniel MacNeil discusses the need to incorporate a REC price as a negative dispatch price into RMP's production cost modeling of Schedule 100 resources. The negative dispatch price would reduce curtailment from Schedule 100 resources during times of negative market prices, which occurs primarily when there is a surplus of renewable generation.[21] RMP discusses a concern that this would make its modeling use recursive logic because the REC price would be set equal to incremental cost, which is an output of the modeling, but also need to be an input to the modeling. Thus, RMP proposes using interpolation to calculate incremental cost due to the recursive nature of the modeling.[22]

Q: Is this "REC price" related to the calculation of "lost value of RECs" discussed earlier?

A: No, the two are separate.[23] As discussed in Section IV above, the "lost value of RECs" refers to the fact that RECs useful for RPS compliance would be retired by Program participants instead of given to PacifiCorp as they would for QFs under Schedule 38. The

[21] MacNeil at 8:158-10:201.
[22] Ex. 1.3 (Data Request Response Sierra Club 4.2 (a)).
[23] *Id.* (Data Request Response Sierra Club 6.2).

"REC" here is not related to RPS compliance, but instead the vehicle by which the incremental cost of Schedule 100 resources is charged to Program participants.[24]

Q: Do you agree with RMP's argument that the incremental cost should be treated as a negative dispatch price, requiring interpolation?

A: No, for multiple reasons. First, it is not economic to dispatch Schedule 100 resources during times of negative prices. This increases the total cost of these resources because not only are costs owed under the terms of the purchase contract but also to pay the negative market prices. Ultimately, Program participants would be responsible for paying the additional cost to generate during negative prices, which is not reasonable if they can be avoided through resource curtailment.

Second, it is contrary to the goal of the Program, which is to add incremental renewable energy production to achieve 100% renewable generation for Program participants. Reducing curtailment from Schedule 100 resources may create the appearance of increased renewable output, but if the net effect is to increase the curtailment of a different renewable facility, then the Schedule 100 resources are not increasing total renewable generation on the system, which is the ultimate goal of the Program.

Third, during times of surplus renewable production it would not be appropriate to favor the dispatch of Schedule 100 resources over resources that have access to external revenue streams such as PTCs.[25] That could increase total dispatch costs charged to ratepayers.

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[24] *Id.* (Data Request Response Sierra Club 4.2 (a)).
[25] See Section VII of this testimony for more about tax credit eligibility and why due to recent legislation, Schedule 100 resources are not expected to generate production tax credits.

Q: Is it still reasonable to account for the prospective curtailment of Schedule 100 resources in the resource valuation?

A: Yes, curtailment can still be accounted for without recursive modeling or negative dispatch pricing. Based on RMP's testimony, the contract cost of Schedule 100 resources would be the same regardless of any curtailment, because the contract price would still be owed to the resource owner for any output that would have otherwise occurred absent the curtailment.[26] In calculating incremental cost, the resource cost side of the equation should not be reduced for curtailment. Conversely, the resource would not generate any avoided cost benefit of energy and capacity during times it is curtailed. So, the benefit side of the incremental cost equation would be reduced for curtailment. The amount of curtailment would not depend on any negative dispatch price because, as I argued earlier, it is not reasonable to include a negative dispatch price.

Q: Are there alternative means to reduce curtailment of Schedule 100 resources and increase total renewable output for Program participants?

A: Yes. Schedule 100 resources could add battery storage to effectively move renewable energy output from times of oversupply to times when needed by the grid. This may be cost-effective depending on the amount of curtailment reduced compared to the incremental cost of a battery.

[26] MacNeil at 8:160-163.

V. OTHER ADJUSTMENTS TO SCHEDULE 38

Q: You have touched on two of the four adjustments to Schedule 38 that RMP proposes for Schedule 100. What are the remaining two?

A: The first adjustment is to account for the costs and benefits of the project's contract term beyond the production cost model study horizon. The second adjustment is to account for "any price-policy, risk, or other modifications it believes are appropriate to ensure the Schedule 100 resource value does not shift any costs or benefits to non-participating customers."[27]

A. Adjustment for Time Horizon

Q: Do you have any comments concerning the first additional adjustment—accounting for costs and benefits of the project beyond the horizon of RMP's production cost modeling?

A: While I agree that Schedule 100 project's costs and benefits beyond the horizon of RMP's production cost modeling should be accounted for, the details will be important. Like CREA witness Higgins, I reserve judgment on this issue until the details of the methodology are presented.

B. Price-Policy Risk

Q: Why does RMP suggest potentially adjusting the Schedule 100 agreements based on risk or other modifications it believes are appropriate?

A: RMP witness MacNeil addresses several risk-related issues associated with potential modifications to Schedule 38 project pricing. First, MacNeil describes how different sets of natural gas and federal carbon policy ("price-policy") scenarios are used when

[27] MacNeil at 18:393-395.

modeling RMP's portfolio in its IRP. For Schedule 38 pricing, RMP uses the Company's Official Forward Price Curve ("OFPC"), which reflects the modeling scenario that reflects RMP's current expectation for natural gas prices and federal carbon policy.[28] For Schedule 100, RMP "expects" to provide results under the medium gas/no federal carbon policy scenario ("MN"), the low gas price/no federal carbon policy scenario ("LN"), and the high gas price/high carbon price ("HH") price-policy scenarios.[29] MacNeil notes that "[t]his is comparable to the analysis the Company has used to justify the prudence of recent non-QF resource procurement."[30]

Q: What is your recommendation?

A: I recommend that when evaluating the value (avoided cost) of Schedule 100 projects, the Company also present the analysis using the medium natural gas/social cost of GHG ("SC") scenario.

Q: What is the SC scenario?

A: This scenario uses medium natural gas price assumptions plus the social cost of GHG emissions from the Washington Utilities and Transportation Commission Docket U-19730 with no additional federal carbon regulations. As described in the PacifiCorp IRP:

> The SCGHG scenario is in compliance with Washington RCW 19.280.030 including an adjusted cost of greenhouse gas emissions reflecting inflation, defined by the Washington Utilities and Transportation Commission.[fn] The social cost of greenhouse gas emissions is assumed to apply in all years of the study horizon. The social cost of greenhouse gases is applied such that the price for the SC-GHG is reflected in market prices and dispatch costs for the purposes of developing each portfolio (i.e., incorporated into capacity expansion optimization modeling). Aligned with Washington staff suggested treatment, system operations

[28] *Id*. at 12:248-249.
[29] *Id*. at 13:275-277
[30] *Id*.

> also include the SC-GHG once the portfolios are determined, presenting the risk that this operational assumption will not be aligned with actual market forces (i.e., market transactions at the Mid-Columbia market do not reflect the social cost of greenhouse gases and PacifiCorp does not directly incur emission costs at the price assumed for the social cost of greenhouse gases).[31]

The incremental value of societal costs implicit in this scenario are shown in Figure 8.4 of Volume 1 of the PacifiCorp 2025 IRP and repeated here as **Error! Reference source not found.**.[32] The black line with the large circles labeled "25 IRP SCGHG" corresponds to the cost referenced above.

Q: What are these social costs?

A: The social costs are what are known as externalities. That is, costs that are incurred by parties but that are not part of an economic transaction and not included in the transaction's price. In this context, they are real costs that are not accounted for when considering which power plants to build and how the electric system is operated. They should be treated as an additional variable cost of operating polluting fossil fueled generators.

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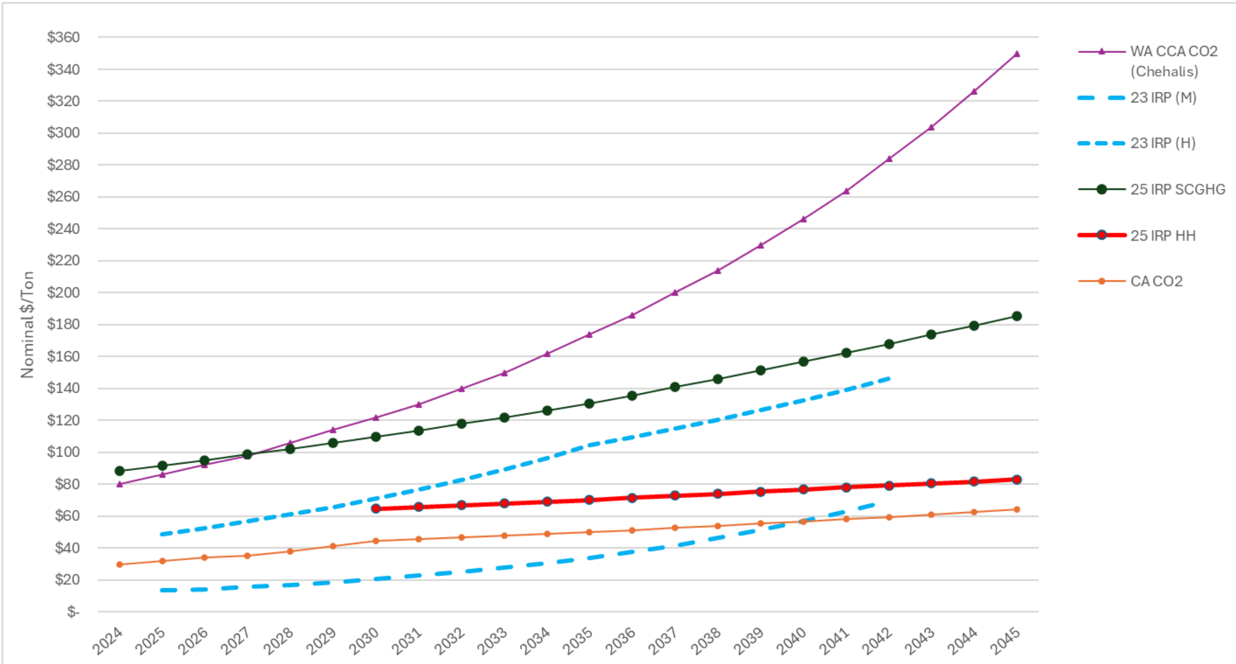
[31] *PacifiCorp 2025 Integrated Resource Plan*, Utah Pub. Serv. Comm'n, Dkt. No. 25-035-22, 2025 Integrated Resource Plan Volume I at 197 (Mar. 31, 2025), *available at* https://pscdocs.utah.gov/electric/25docs/2503522/339034RMP2025IRPVlmI3-31-2025.pdf.
[32] *Id*. at 198.

Figure 1. Social Cost Externality Values from PacifiCorp IRP



Q: How much does this add to the cost of generation from a natural gas combed cycle and a coal steam generator?

A: Looking at Figure 1, the social cost of carbon dioxide (“CO_2”) in 2030 would be approximately $110 per ton CO_2. For illustrative purposes, using US average natural gas power plant carbon emissions rate (0.96 lb. CO_2/kWh)[33] would result in a cost adder to a gas power plant of about $52/MWh. For a coal-steam power plant (2.31 lb. CO_2/kWh),[34] the adder would increase to approximately $127/MWh.

[33] U.S. Energy Information Administration, *2023 US Utility Scale Net Electricity Generation and Resulting CO2 Emissions by Fuel in 2023*, *available at* https://www.eia.gov/tools/faqs/faq.php?id=74&t=11 (last accessed Sept. 19, 2025).
[34] *Id*.

Q: What is the impact of including these environmental externality costs?

A: Adding these costs into production cost and system expansion modeling would increase the amount of renewable power planned for, built, and used.

Q: If generators that are more costly because of the inclusion of these environmental externalities are built, wouldn't this just add costs to Utah residents and businesses?

A: Not in the larger picture, and in fact would better reflect the costs that the people of Utah and throughout the PacifiCorp service area would actually be experiencing: not just the costs incurred by RMP and passed along to them in rates, but also the externality costs borne by them caused by the emissions from fossil fuel powered generators.

Q: **Do you recommend that this scenario be used for monetizing the value for the avoided cost benefits associated with a Schedule 100 resources?**

A: No. While I find considering externality costs in planning to be appropriate, I do not recommend that they be used to monetize the avoided costs associated with Schedule 100 resource pricing. Still, the Commission should see the results of this scenario to have a fuller understanding of the benefits of adding renewable generation to the PacifiCorp grid. As the Commission has recognized in the context of IRP planning, "external costs associated with the electric utility industry are uncertain, but clearly not zero" and "prudent business planning must evaluate risk and uncertainty."[35] Just as the Commission has found that an analysis of environmental risk is useful in IRP planning, having a better understanding of externality costs when evaluating the value (avoided cost) of Schedule 100 projects will also be useful.

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[35] *In the Matter of Analysis of an Integrated Resource Plan for PacifiCorp*, Utah Pub. Serv. Comm'n, Dkt. No. 90-2035-01, Reports and Order on Standards and Guidelines at 10, 11 (June 18, 1992), *available at* https://pscdocs.utah.gov/electric/90docs/90203501/121607RprtOrdrStndrdsGdlnes6-18-1992.pdf.

Q: Witness MacNeil further states: "The Company will also provide an adjusted valuation that incorporates REC value and any price-policy, risk, or other modifications it believes are appropriate to ensure the Schedule 100 resource value does not shift any costs or benefits to non-participating customers."[36] You have discussed REC values and price-policy risk. What about the last clause here, "other modifications" appropriate to prevent cost or benefit shifts between participating and non-participating ratepayers?

A: While I agree with the principle that Schedule 100 must not shift costs or benefits between participating and non-participating customers, an open-ended statement such as what seems to be suggested here is inappropriate. If RMP identifies what it believes to be a cost or benefit shift, it should not have the unilateral power to impose a perceived remedy without full due process, i.e., review by intervenors and a decision by the Commission.

VI. AVOIDED RENEWABLE COSTS MUST REFLECT RENEWABLE DEVELOPMENT REALITIES

Q: CREA witness Higgins notes that any analysis of the avoided cost of solar must reflect the impact on PTCs due to the recently enacted "One Big Beautiful Bill."[37] He further notes that the loss of PTCs for solar and wind must be accounted for in the avoided cost calculations used to calculate the value of Schedule 100 renewable projects.[38] Do you concur?

[36] MacNeil at 18:392-395.
[37] Higgins at 12:269-270.
[38] *Id*. at 13:289-296.

A: Yes, the loss of the PTCs will have a major impact on the economics of solar generators. Currently, the Inflation Reduction Act provides for a 30% investment tax credit and PTC of $27.50 for every megawatt-hour generated by solar.[39] There are also "Bonus Credits" that can apply if the project contains at least a prescribed minimum amount of U.S. manufactured content and/or is located at a brownfield site.[40] However, due to the updated federal legislation, projects must now be under construction by July 4, 2026 or placed in service by December 31, 2027 in order to claim PTCs.[41] Given that it is unlikely that Schedule 100 projects will meet either of the deadlines, and that PacifiCorp's proxy solar resource is not assumed to come online until 2032, the end of these tax credit must be accounted for in the avoided cost calculations.

Q: Why else might these changes to the PCT and the impacts of other federal policies on utility-scale solar be important?

A: As noted, the loss of the PCT as well as other federal policies (e.g., tariffs and resulting supply chain issue) will likely increase the cost of solar. This cost increase could have an impact on the resource selection in PacifiCorp's IRP. That is, if a solar resource is selected by PacifiCorp's current modeling for economic reasons rather than policies ones, then increasing the cost of solar could change the resource selection and defer the solar resource or eliminate it all together from the IRP. If a Schedule 100 project is valued for avoided cost purposes, this change would need to be accounted for.

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[39] United States Environmental Protection Agency, *Summary of Inflation Reduction Act Provisions Related to Renewable Energy*, *available at* https://www.epa.gov/green-power-markets/summary-inflation-reduction-act-provisions-related-renewable-energy (last updated July 29, 2025).
[40] *Id*.
[41] Keith Martin et al., *Effects of "One Big Beautiful Bill" on Projects*, Norton Rose Fulbright (July 7, 2025), *available at* https://www.projectfinance.law/publications/2025/july/effects-of-one-big-beautiful-bill-on-projects/.

VII. CONCLUSION

Q: Please summarize your conclusions and recommendations to the Commission.

A: My recommendations are:

1. Schedule 38 is an appropriate starting point for valuing Schedule 100 resources and setting the associated rate.
2. Schedule 100 must ensure that the associated project is responsible for only the interconnection and transmission upgrade costs needed to allow the project to connect to the PacifiCorp transmission grid and no more.
3. The Schedule 100 project valuation should not be adjusted for any "lost value of Renewable Energy Credits ("RECs")" from a proxy renewable resource.
4. RECs generated by Schedule 100 projects should be retired and not resold or given to PacifiCorp.
5. Schedule 100 resources should not be modeled with a negative dispatch price equal to the incremental cost of Schedule 100 resources.
6. When presenting potential pricing to the Commission for approval, RMP should include a price analysis using social costs when considering the benefits of a Schedule 100 project.
7. The Commission should reject RMP's request for open-ended authority to impose additional pricing adjustments under the rubric of "other modifications." If RMP identifies what it believes to be a cost or benefit shift, it should not have the unilateral authority to impose a remedy without full Commission review and an opportunity for intervenor input.

8. Avoided cost calculations must reflect the loss of federal PTCs and other federal policy changes affecting solar costs, as these materially affect the economics of Schedule 100 projects and PacifiCorp's IRP resource selection.

Q: Does this conclude your testimony?

A: Yes.