**BEFORE THE UTAH PUBLIC SERVICE COMMISSION**

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| 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 |

# SURREBUTTAL TESTIMONY

# AND EXHIBIT

# OF

# KEVIN C. HIGGINS

**On Behalf of**

**Community Renewable Energy Agency**

**December 11, 2025**

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## LIST OF EXHIBITS

## 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 AND REBUTTAL TESTIMONY IN THIS PROCEEDING ON BEHALF OF THE COMMUNITY RENEWABLE ENERGY AGENCY ("AGENCY")?**

A. Yes.

**Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?**

A. My surrebuttal testimony responds to the rebuttal testimonies of Rocky Mountain Power ("RMP") witnesses Daniel J. MacNeil and Craig M. Eller, Division of Public Utilities ("Division") witness Timothy M. Lenell, and Office of Consumer Services ("OCS") witness Anthony Sandonato on the subjects of resource valuation and rate design.[1] In particular, my surrebuttal addresses the appropriateness of using the Schedule 38 method to value the resource(s) procured by the Utah Community Clean Energy Program ("Program"), the treatment of Renewable Energy Certificates ("RECs") in the valuation of

[1] I also refer to the PVRR(d) proposal made by Western Resources Advocate ("WRA") Karl Boothman in his direct testimony.

the Program resource(s), and whether the Commission should permit Schedule 100 to be a credit.

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

A. No.

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

A. I offer the following conclusions and recommendations in my surrebuttal:

- The Commission should not approve any Program resource valuation that assumes the Program resource would displace a proxy solar resource that would be eligible to earn production tax credits ("PTCs"). This assumption has a pronounced adverse impact on the Schedule 38 avoided cost calculation and is entirely improper in light of current Federal tax law. Yet both versions of the 2025 IRP being advanced by RMP for valuing the Program resource rely on this incorrect assumption.

- RMP maintains that it does not have an updated resource portfolio at this time. The Agency is not in a position to develop an alternative resource portfolio for RMP, but we do know that the proxy solar resources in the current portfolio will not be eligible for PTCs. Therefore, I conclude that the 2025 Utah IRP with the assumed displaced PTCs removed from the avoided cost calculation is the most reasonable, albeit imperfect, Schedule 38 platform available at the current time.

- The use of the PVRR(d) method to value the Program resource as proposed by WRA witness Boothman may be a necessary fallback option if the use of the Schedule 38 method for Program resource valuation turns out to be driven by meritless assumptions. The assertion by Division witness Lenell that use of the PVRR(d) method is more susceptible to inter-year subsidization than the Schedule 38 method is misplaced and should not be given any weight by the Commission.

- Another possible alternative is for the avoided cost of the Program resource to be considered on an energy-only basis, *i.e.*, without assuming the displacement of a proxy resource. Under such an approach, the Program resource would not receive a credit for displacing capital costs, but neither would costs be attributed to it for lost PTCs. Also,

without a displaced proxy resource, there would not be a basis for any party to assert that Program participants should have to compensate non-participants for the "lost value" of RECs. In the absence of a credible IRP baseline, an energy-only avoided cost option warrants consideration.

- Charging Program participants for "the lost value of RECs" as part of the resource valuation calculation should be rejected by the Commission. The "lost REC benefit" 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 to date. 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.

- RMP argues that the Agency should not have an option to decline to retire the RECs generated by the Program resource, asserting that such an option would contravene the Program's clean energy goals. The Company's argument on this point, as well those of several other parties, should be rejected. In my rebuttal testimony, I explained at length why the Agency turning back the RECs to the system would *not* contravene the Agency's clean energy goals, particularly if the RECs were turned back out of economic necessity. I also explained how a hybrid option would facilitate the Agency's retirement of RECs in years in which there was no assumed displaced proxy plant, while allowing the Agency to make an economic decision as to whether or not to retire RECs in years in which Program participants would be required to purchase "lost RECs" from non-participants, if so ordered by the Commission.

- The Company opposes allowing Schedule 100 to ever be a credit, even if the economic benefits of the program were to exceed the economic costs. The Company offers three justifications for its position, each of which should be rejected by the Commission, as none of them are valid.

    - RMP argues that Schedule 100 cannot logically be a credit because if a renewable resource acquisition was able to provide incremental net benefits, then the Company (already) would have acted on its own accord to procure it for the benefit of the system. The premise of this argument is patently untrue and should be rejected.
    - RMP proposes an exceedingly narrow definition of Program benefits, which excludes avoided costs of any kind, and then proceeds to argue that restricting Schedule 100 from ever being a credit would not shift the narrowly-defined benefits to non-participants. The Company's argument is disingenuous and should be rejected by the Commission.
    - RMP incorrectly characterizes a Schedule 100 credit as a payment by non-participants to participants representing "an undue subsidy between customers." RMP overlooks the fact that, properly calculated, Schedule 100 would only be a credit if incremental benefits exceed the incremental costs in a particular year. In

such a case, participants would not receive a "payment" from anybody; rather, participants' all-in rates would simply be lower than they would be absent the Program resource. Such a situation is no different than what occurs in normal ratemaking when one class has lower average rates than another because the cost to serve it is lower. RMP's argument on this point is contrary to the principles of cost causation as applied in normal ratemaking and therefore should be rejected by the Commission.

## II. RESOURCE VALUATION METHOD

**Q. IN BOTH YOUR REBUTTAL AND DIRECT TESTIMONY, YOU RAISED 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. AFTER REVIEWING RMP'S REBUTTAL TESTIMONY, DO YOU CONTINUE TO HAVE THESE CONCERNS?**

A. Yes, very much so. RMP's rebuttal filing confirms the apprehensions expressed in my rebuttal testimony that the Company's use of the Schedule 38 method will produce a Program resource valuation that is without merit. Specifically, RMP witness MacNeil confirms that the Company intends to value the Program resource using planning assumptions that are fundamentally unreasonable under current Federal tax law, stating explicitly that the avoided cost calculation using the Schedule 38 method should not be modified to reflect the fact that the proxy resources will no longer be eligible for PTCs.[2]

[2] Rebuttal Testimony of Daniel J. MacNeil, lines 252-256.

As I explained in my rebuttal testimony, there are currently two versions of the IRP that RMP is poised to apply 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 PTCs, an assumption that no longer reasonably applies under current Federal tax law. Yet, Mr. MacNeil states that it is precisely these two frameworks, each suffering from this incorrect premise, that RMP intends to use for valuing the Program resource.

**Q. PLEASE EXPLAIN.**

A. The two versions of the 2025 IRP advocated by that Company for valuing the Program resource are the so-called "2025 Utah IRP" and the "Final 2025 IRP."[3] According to the 2025 Utah IRP, the next displaceable proxy solar resource is located in the Willamette Valley, Oregon. Consistent with the Schedule 38 method, this plant would be displaced in 2032.[4] In contrast, according to the Final 2025 IRP, the next displaceable proxy solar resource is a plant located at Naughton, Wyoming that would be displaced in 2031.[5] Of the two, RMP recommends using the Final 2025 IRP preferred portfolio as the framework for valuing the Program resource, because the Company believes it "represents the best available information." However, RMP recognizes that the 2025 IRP has been contested as part of the Schedule No. 38 proceeding, Docket No. 25-035-30. Consequently, Mr. MacNeil indicates that, at this time, the Company intends to provide avoided cost results

[3] Rebuttal Testimony of Daniel J. MacNeil, lines 125-144. *See also 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.
[4] *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 4.
[5] *Id.*

based on *both* the Utah 2025 IRP preferred portfolio and the Final 2025 IRP preferred portfolio.[6]

**Q. HOW DO THE AVOIDED COSTS CALCULATED USING THE FINAL 2025 IRP COMPARE TO THOSE USING THE 2025 UTAH IRP?**

A. Notably, the 15-year levelized avoided cost for a solar tracking resource drops from $25.51/MWh using the 2025 Utah IRP[7] to the absurdly low rate of just $3.84/MWh using the Final 2025 IRP[8] for the period 2026-2041, according to the Company's Q2 Avoided Cost Compliance Filing in Docket No. 03-034-14.

**Q. HAVE THERE BEEN ANY COMMISSION DECISIONS CONCERNING AVOIDED COSTS SINCE MR. MACNEIL'S REBUTTAL TESTIMONY WAS FILED?**

A. Yes. On November 28, 2025, the Commission issued its Order in Docket No. 25-035-T03, *declining* to adopt the Schedule 37 tariff changes proposed by the Company on April 23 of this year.[9] The avoided cost rates for Schedule 37 are calculated using the same general method the Commission has approved for Schedule 38 with certain identified modifications,[10] and therefore, are instructive for this docket.

In declining to adopt the tariff changes RMP requested, the Commission noted that "RMP's proposed avoided cost prices constitute a substantial reduction in current rates."[11] Significantly, the "substantial reduction" in avoided costs called out by the Commission

[6] Rebuttal Testimony of Daniel J. MacNeil, lines 139-144.
[7] *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), Appendix B.1.
[8] *Id*. Appendix D.1.
[9] Docket No. 25-035-T03, Order at 10.
[10] *Id.*at 7.
[11] *Id.* at 9.

was calculated using the assumptions of the 2025 Utah IRP, not the Final 2025 IRP favored by RMP in this docket, which would further reduce solar avoided costs by an astounding 85%.

The Commission also recognized that RMP "has made significant changes in its modeling that have raised understandable concerns among stakeholders given the substantial decrease in avoided cost prices."[12] Among the changes noted by the Commission are the replacement of the Company's longstanding modeling tool, GRID, with its PLEXOS model, and the implementation of Jurisdictional Modeling for the first time in the development of its 2025 IRP.[13]

**Q. WHAT ARE THE IMPLICATIONS OF THE COMMISSION'S SCHEDULE 37 ORDER FOR THIS DOCKET?**

A. The concerns raised by parties to the Schedule 37 docket also apply to this docket. It follows that the caution the Commission exercised in refraining from approving dramatically lower avoided cost prices based on new and unvetted modeling techniques[14] should reasonably apply to this case as well. Indeed, RMP's proposals in this docket are even more alarming than what the Company proposed in the Schedule 37 docket, warranting even greater caution, given the Company's proposal to use a set of IRP assumptions that drives solar avoided costs down by another 85% compared to the assumptions used in the Schedule 37 docket.

Moreover, whereas the challenges to the Schedule 37 tariff proposal focused on process and structural changes to the modeling, in this docket there is a clearcut basis for

[12] *Id*.
[13] *Id.*
[14] *Id.* at 9-10.

rejecting the modeling assumptions proposed by RMP on factual grounds, namely, the Company's operating assumption that the Program resource would displace proxy resources that would be eligible for PTCs. As I demonstrated in my rebuttal testimony (and will not repeat here) there is no longer any factual basis for such an assumption.

**Q. WHAT ARE THE IMPLICATIONS OF CONTINUING TO ASSUME THAT THE PROXY SOLAR RESOURCES IN THE COMPANY'S IRPS ARE ELIGIBLE FOR PTCS?**

A. This assumption has a dramatic negative effect on Schedule 38 avoided cost, irrespective of whether the 2025 Utah IRP or the Final 2025 IRP is used, but with the latter having the more draconian impacts.

To appreciate the significance of these impacts, it is instructive to examine the workpapers filed by the Company on September 30, 2025 in support of its Q2 avoided cost compliance filing in Docket No. 03-035-14. In Table KCH-1-SR, below, I reproduce the "energy only" component of avoided costs for a representative solar tracking facility, calculated by RMP using the 2025 Utah IRP assumptions. Note well the *negative* avoided energy costs projected for each month starting in 2032 and continuing to the end of 2041, averaging $(27.20) per MWh over that ten-year period.

**Table KCH-1-SR**[15]

**Avoided Energy Costs - Scheduled Hours ($/MWh)**

**QF - Sch38 - UT - Solar T - 80.0 MW and 30.2% CF**

| | | Winter Season | | | | | Summer Season | | | | Winter Season | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
| **Energy Only** | | | | | | | | | | | | | |
| 2026 | $20.65 | $20.87 | $13.41 | $0.60 | ($0.27) | $8.50 | $21.79 | $37.65 | $45.27 | $25.16 | $10.83 | $22.29 | $28.71 |
| 2027 | $22.61 | $30.58 | $21.71 | $8.48 | $10.16 | $13.52 | $20.72 | $33.51 | $38.19 | $23.47 | $15.34 | $24.92 | $33.82 |
| 2028 | $25.61 | $37.11 | $24.05 | $9.55 | $12.37 | $14.79 | $19.34 | $36.82 | $41.88 | $31.54 | $20.61 | $30.59 | $40.92 |
| 2029 | $29.10 | $36.05 | $33.59 | $16.13 | $11.80 | $17.51 | $26.83 | $40.23 | $41.34 | $36.67 | $25.98 | $30.18 | $41.83 |
| 2030 | $25.98 | $38.45 | $26.74 | $14.27 | $8.46 | $12.04 | $23.69 | $38.77 | $37.00 | $33.10 | $22.97 | $32.10 | $37.31 |
| 2031 | $24.92 | $42.01 | $27.01 | $11.86 | $10.31 | $11.00 | $18.21 | $34.33 | $36.92 | $31.31 | $20.15 | $35.42 | $38.99 |
| 2032 | ($16.28) | ($6.05) | ($8.43) | ($32.35) | ($19.80) | ($20.93) | ($12.33) | ($22.28) | ($11.15) | ($14.15) | ($23.88) | ($3.34) | ($4.48) |
| 2033 | ($18.36) | ($8.12) | ($12.65) | ($33.25) | ($20.84) | ($22.11) | ($15.04) | ($22.44) | ($14.51) | ($16.22) | ($26.42) | ($7.11) | ($5.81) |
| 2034 | ($19.75) | ($10.21) | ($14.09) | ($31.91) | ($21.47) | ($30.23) | ($13.12) | ($24.37) | ($11.99) | ($20.54) | ($23.84) | ($9.66) | ($13.24) |
| 2035 | ($22.79) | ($11.68) | ($13.94) | ($32.55) | ($21.38) | ($29.47) | ($23.12) | ($26.50) | ($21.04) | ($23.90) | ($23.84) | ($11.51) | ($13.63) |
| 2036 | ($22.97) | ($26.92) | ($28.76) | ($32.87) | ($20.55) | ($18.47) | ($11.68) | ($22.75) | ($20.96) | ($28.65) | ($30.99) | ($23.29) | ($25.26) |
| 2037 | ($26.60) | ($23.12) | ($21.49) | ($37.53) | ($28.04) | ($18.23) | ($20.27) | ($27.43) | ($31.56) | ($31.69) | ($39.20) | ($16.81) | ($20.65) |
| 2038 | ($32.85) | ($31.88) | ($20.47) | ($42.47) | ($29.82) | ($32.05) | ($29.30) | ($34.08) | ($42.32) | ($35.11) | ($39.73) | ($21.35) | ($23.18) |
| 2039 | ($35.62) | ($31.46) | ($24.94) | ($40.99) | ($36.48) | ($35.57) | ($34.60) | ($36.36) | ($50.05) | ($34.40) | ($40.92) | ($17.08) | ($21.23) |
| 2040 | ($38.65) | ($27.71) | ($31.95) | ($39.56) | ($43.93) | ($43.82) | ($38.71) | ($40.44) | ($48.46) | ($38.01) | ($40.10) | ($18.32) | ($19.86) |
| 2041 | ($38.12) | ($23.45) | ($29.88) | ($39.96) | ($45.90) | ($42.05) | ($41.91) | ($39.28) | ($46.34) | ($35.90) | ($43.82) | ($10.46) | ($19.92) |
| 2042 | $9.91 | $14.33 | $13.35 | $3.62 | $8.07 | $5.09 | $10.42 | $10.65 | $13.87 | $10.21 | $3.90 | $16.09 | $15.99 |
| 2043 | $9.34 | $11.16 | $21.79 | $4.84 | $4.40 | $5.40 | $10.72 | $7.94 | $10.55 | $10.05 | $3.29 | $17.79 | $13.30 |

**Q. PLEASE EXPLAIN THE NEGATIVE AVOIDED ENERGY COSTS OVER THAT TEN YEAR PERIOD.**

A. Using the 2025 Utah IRP assumptions, 2032 is the first year in which the proxy resource is displaced (and an avoided capacity credit is recognized). Negative avoided energy costs means that as an offset to the credit for avoided capacity cost, a QF (or Program resource) would have to "pay" RMP to take its energy output. Absent PTCs, one would expect the avoided energy cost to hover near zero starting in 2032, because the QF (or Program resource) is assumed to be displacing a solar resource that has a marginal energy cost of

[15] Source: Docket Nos. 03-035-14 & 25-035-30, *Rocky Mountain Power's Quarterly Compliance Filing – 2025.Q2 Avoided Cost Input Changes*, (September 30, 2025) Workpaper RMP Att 2 Apndx B2 9-30-25, Table 2.

zero. Relatively small deviations from zero (positive or negative) would be expected due to differences in the hourly production profile of the QF (or Program resource) compared to the proxy resource. For example, one would expect a solar resource located in Utah to be more productive than one of equal size located in the Willamette Valley, all things being equal. Indeed, as shown in Table KCH-1-SR, the avoided energy component is slightly positive in 2042[16] and 2043 in the Company's workpaper, despite the displacement of the proxy resource.

The negative avoided energy costs correspond to the ten-year period that RMP assumes the PTCs would apply.[17] That is, as part of the Schedule 38 calculation, the QF (or Program resource) must compensate the Company for the lost value of PTCs that otherwise would have been produced by the displaced proxy resource. And as I stated above, the impact of paying for the lost PTCs is very material.

**Q. WHAT ARE THE CORRESPONDING "ENERGY ONLY" AVOIDED COSTS IF THE FINAL 2025 IRP IS USED?**

A. In Table KCH-2-SR, below, I reproduce the corresponding "energy only" component of avoided costs for a solar tracking facility using the Final 2025 IRP assumptions, as calculated by RMP in the Q2 avoided cost compliance filing. Consistent with the results I discussed above, the period corresponding to the assumed displaced PTCs (2031-2040 in this instance) yields negative avoided energy costs, but even more dramatically negative than the 2025 Utah IRP case, averaging $(54.99) per MWh. This dramatically negative

[16] 2042 is the first year after the PTCs assumed for the Willamette Valley proxy solar plant expire.
[17] *See also* RMP's Response to CREA Data Request 7.2, which is included in Agency Exhibit 8.1.

225 "lost PTC" charge is a major driver in causing the Company's proposed Schedule 38
226 avoided cost to fall to absurdly low levels.[18]

**Table KCH-2-SR**[19]

**Avoided Energy Costs - Scheduled Hours ($/MWh)**

**QF - Sch38 - UT - Solar T - 80.0 MW and 30.2% CF**

| | | Winter Season | | | | | Summer Season | | | | Winter Season | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
| **Energy Only** | | | | | | | | | | | | | |
| 2026 | $20.03 | $21.24 | $13.75 | $0.09 | $1.74 | $11.05 | $20.71 | $35.42 | $39.04 | $23.16 | $11.49 | $24.76 | $30.05 |
| 2027 | $22.41 | $27.15 | $22.33 | $5.89 | $7.72 | $13.08 | $19.56 | $37.16 | $41.94 | $23.38 | $14.39 | $21.91 | $30.05 |
| 2028 | $23.54 | $36.46 | $17.52 | $4.60 | $8.15 | $11.86 | $17.34 | $36.98 | $40.96 | $31.43 | $19.58 | $27.09 | $43.33 |
| 2029 | $26.41 | $32.81 | $27.54 | $8.50 | $7.44 | $14.96 | $23.08 | $40.43 | $38.97 | $37.09 | $23.25 | $30.87 | $40.41 |
| 2030 | $23.37 | $42.49 | $28.06 | $5.19 | ($0.19) | $5.99 | $23.37 | $35.32 | $37.36 | $31.35 | $17.64 | $31.98 | $47.07 |
| 2031 | ($49.07) | ($47.25) | ($50.37) | ($49.14) | ($49.42) | ($49.06) | ($49.20) | ($48.13) | ($48.91) | ($49.15) | ($50.12) | ($49.16) | ($48.71) |
| 2032 | ($50.40) | ($49.90) | ($49.88) | ($51.38) | ($48.95) | ($50.54) | ($50.40) | ($51.35) | ($49.38) | ($49.83) | ($48.58) | ($55.01) | ($51.22) |
| 2033 | ($51.19) | ($48.73) | ($50.51) | ($51.65) | ($50.14) | ($52.00) | ($51.15) | ($50.27) | ($51.37) | ($50.58) | ($53.14) | ($51.39) | ($54.46) |
| 2034 | ($52.67) | ($53.57) | ($52.57) | ($52.52) | ($51.87) | ($52.44) | ($52.22) | ($51.03) | ($52.22) | ($53.57) | ($53.58) | ($54.66) | ($56.80) |
| 2035 | ($53.83) | ($56.88) | ($54.34) | ($50.58) | ($53.68) | ($54.00) | ($53.73) | ($56.57) | ($53.86) | ($53.57) | ($51.70) | ($55.14) | ($50.32) |
| 2036 | ($55.03) | ($60.42) | ($56.26) | ($53.81) | ($55.80) | ($55.84) | ($55.68) | ($52.93) | ($56.71) | ($55.70) | ($53.49) | ($48.83) | ($54.30) |
| 2037 | ($58.01) | ($58.76) | ($59.52) | ($56.01) | ($57.65) | ($58.21) | ($57.54) | ($57.42) | ($57.68) | ($57.48) | ($58.94) | ($59.26) | ($61.65) |
| 2038 | ($57.94) | ($58.19) | ($60.41) | ($58.18) | ($56.87) | ($57.02) | ($57.50) | ($56.84) | ($57.50) | ($58.89) | ($57.73) | ($58.68) | ($62.16) |
| 2039 | ($59.63) | ($60.37) | ($62.48) | ($58.29) | ($59.87) | ($59.26) | ($59.82) | ($57.76) | ($60.20) | ($60.27) | ($59.42) | ($61.59) | ($57.13) |
| 2040 | ($62.08) | ($62.30) | ($63.77) | ($60.45) | ($60.58) | ($60.33) | ($63.60) | ($65.38) | ($60.05) | ($62.14) | ($63.04) | ($69.34) | ($48.06) |
| 2041 | ($1.22) | ($2.58) | ($2.14) | ($1.57) | ($1.62) | ($0.52) | ($0.31) | ($1.45) | ($1.92) | ($0.91) | $0.64 | $9.28 | ($18.25) |
| 2042 | ($3.73) | $0.54 | ($2.42) | ($1.94) | ($0.86) | ($0.44) | ($1.35) | ($2.50) | ($1.85) | ($2.43) | $0.42 | ($2.57) | ($65.73) |
| 2043 | ($3.20) | ($5.46) | ($3.78) | ($1.31) | ($3.06) | ($0.79) | ($0.82) | ($5.67) | ($5.53) | ($1.12) | ($8.72) | ($6.07) | $5.48 |

227

228 **Q. ARE THE COSTS OF THE "LOST PTCS" THAT WOULD BE CHARGED TO**
229 **THE PROGRAM RESOURCE DISTINCT FROM THE COST OF THE "LOST**
230 **RECS" THAT RMP ALSO PROPOSES TO CHARGE?**

231 A. Yes. The "lost PTC" charge and the "lost REC" charge are distinct and additive costs to
232 the Program resource under RMP's Program resource valuation proposal.

[18] *See also* RMP's Response to CREA Data Request 7.1, which is included in Agency Exhibit 8.1.
[19] Source: Docket Nos. 03-035-14 & 25-035-30, *Rocky Mountain Power's Quarterly Compliance Filing – 2025.Q2 Avoided Cost Input Changes* (September 30, 2025), Workpaper RMP Att 8 Apndx D2 9-30-25, Table 2.

**Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION CONCERNING ANY PTC-RELATED ASSUMPTIONS USED IN VALUING THE PROGRAM RESOURCE?**

A. The Commission should not approve any Program resource valuation that assumes the Program resource would displace a proxy solar resource that would be eligible to earn PTCs. This assumption has a pronounced adverse impact on the Schedule 38 avoided cost calculation and is entirely improper in light of current Federal tax law.

Taking on the responsibility for the incremental costs of a new renewable resource is a serious endeavor for the Agency. A sophisticated model with grossly incorrect inputs will not produce reasonable results, a phenomenon long known as "garbage in, garbage out." The evidence in this case demonstrates that the Program resource will not displace PTCs from either the Willamette Valley or Naughton proxy plants, and the Commission should reject any attempt by the Company to calculate the Program resource valuation that assumes such a displacement will occur. Such assumptions would undermine the credibility of the Program resource valuation and cause economic harm to Program participants by falsely attributing substantial nonexistent costs to them.

In that regard, the Commission's statement in its Schedule 37 order is on point:

> We are also mindful of SLC Corp's concerns about disincentivizing new generation. Of course, this factor is not directly material to the calculation of avoided cost prices. However, given recent federal legislative decisions that have suddenly and adversely impacted prospective renewable resources, the public interest demands some caution before approving dramatically lower avoided cost prices that largely depend on new and unvetted modeling techniques.[20]

[20] Docket No. 25-035-T03, Order at 9-10.

Just as the economic consequences of using new and unvetted modeling techniques is a serious concern, the public interest is also harmed if new generation is disincentivized by employing valuation assumptions that would assign millions of dollars of "lost PTC" costs to the Program resource when the attribution of such lost PTCs is known to be false.

**Q. HAS RMP SUGGESTED ANY ALTERNATIVES TO USING THE INCORRECT ASSUMPTION THAT THE PROXY SOLAR RESOURCES WOULD BE ELIGIBLE TO EARN PTCS?**

A. Mr. MacNeil states that the Company will have an updated resource portfolio that incorporates updated inputs, including updated tax credit developments, as soon as it files its 2025 IRP Update, which is expected on March 31, 2026. He suggests that if the approval of Program resource value continues beyond the filing of the 2025 IRP Update, it may be appropriate for the Commission to consider updated analysis that reflects the 2025 IRP Update.[21]

**Q. WHAT IS YOUR RESPONSE TO THIS ALTERNATIVE?**

A. The Agency is working diligently to acquire a Program resource and is in the midst of evaluating responses to its Request for Proposals issued May 22, 2025. Time is of the essence, particularly as it may affect bids that intend to qualify for PTCs. The Agency provided the Company a very long lead time to develop a reasonable and workable valuation method. If the Program resource is valued using the IRP assumptions outlined in Mr. MacNeil's rebuttal testimony, the valuations developed by the Company will be neither reasonable nor workable. Yet further delay is unwelcome. While updated

[21] Rebuttal Testimony of Daniel J. MacNeil, lines 257-266.

assumptions provided at the end of March 2026 may address changes in Federal tax law, the recent history of the Company's IRP process does not instill confidence that the overall assumptions and modeling that the Company will make available on that date will necessarily be comprehensible or reasonable.

**Q. IN LIGHT OF THE CONCERNS YOU'VE IDENTIFIED, WHAT IS YOUR RECOMMENDATION TO THE COMMISSION REGARDING THE APPROPRIATE METHOD FOR VALUING THE PROGRAM RESOURCE?**

A. If the Schedule 38 method is used in combination with either the 2025 Utah IRP or Final 2025 IRP, the Commission should order RMP not to employ the incorrect assumption that the proxy solar resources would be eligible to earn PTCs. All PTC-related impacts on the avoided cost calculation should be eliminated from the analysis.

**Q. IF THE PROXY SOLAR RESOURCES ARE INELIGIBLE FOR PTCS, WOULDN'T THAT CHANGE THE LIKELIHOOD THAT THE PROXY SOLAR PLANT WOULD BE DEVELOPED?**

A. I expect that it would, yet RMP maintains that "The Company does not have an updated resource portfolio at this time."[22] The Agency is not in a position to develop an alternative resource portfolio for RMP, but we do know that the proxy solar resources in the current portfolio will not be eligible for PTCs. Therefore, I conclude that the 2025 Utah IRP with the assumed displaced PTCs removed from the avoided cost calculation is the most reasonable, albeit imperfect, Schedule 38 platform available at the current time.

[22] *Id.* at lines 266-267.

In addition, if the Schedule 38 method is used, the qualifications I recommended in my direct testimony concerning interconnection costs, transmission upgrade costs, treatment of RECs, and curtailment should also be adopted.

**Q. IS THERE A SET OF DEFAULT IRP ASSUMPTIONS IMPLICIT IN THE COMMISSION'S SCHEDULE 37 DECISION?**

A. Perhaps. The Commission's decision declining to adopt the Schedule 37 tariff changes proposed by the Company retains the avoided costs determined using assumptions from the 2023 IRP Update. However, while the Commission retained the Schedule 37 avoided cost *rates* that had been previously approved using the 2023 IRP Update, the Commission did not comment on the merits of continuing to use the 2023 IRP Update assumptions for other purposes. While the 2023 IRP Update likely has more realistic projections of solar project development costs than the 2025 IRPs, it also assumes that proxy solar resources will be PTC-eligible, which as we know is no longer the case.

**Q. WHAT ARE YOUR THOUGHTS ON VALUING THE PROGRAM RESOURCE USING AN ALTERNATIVE TO THE SCHEDULE 38 METHOD?**

A. As I stated in my rebuttal testimony, if the Schedule 38 method for Program resource valuation turns out to be driven by meritless assumptions, then it may be preferable to use the PVRR(d) method instead, as proposed by WRA witness Boothman. While the Company appears reluctant to use this approach to value the Program resource,[23] I note that in my experience, this approach is generally used by the Company to justify its own investments when seeking Commission approval.

[23] *Id.* at lines 68-125.

**Q. DIVISION WITNESS LENELL OPPOSES USING THE PVRR(d) METHOD FOR PROGRAM RESOURCE VALUATION. WHAT IS YOUR RESPONSE?**

A. Mr. Lenell claims that the "nature of the PVRR(d) inherently lends itself to inter-year subsidization"[24] because the analysis can be used to produce a levelized value of project net benefits. Mr. Lenell's criticism is misplaced. I have reviewed several PVRR(d) analyses produced by the Company over the years and will attest that *both* the Schedule 38 method and the PVRR(d) method can produce levelized values as well as *annual values* of avoided cost and net benefits. Indeed, the levelized values produced using the PVRR(d) method are derived from detailed annual projections. This rationale offered by the Division for not using the PVRR(d) method should not be given any weight by the Commission.

Mr. Lenell is also wary of using the PVRR(d) method "because it relies on complex system modeling through PLEXOS that would limit the ability for the Commission and the parties to audit and reproduce results even with access to software, assumptions, and portfolio selection."[25] I agree that the complexity of the PVRR(d) method presents its own set of challenges, which is why my primary recommendation is to use the Schedule 38 method with the assumed displaced PTCs removed from the avoided cost calculation. However, given the well-documented problems associated with the 2025 IRP assumptions and portfolios, it may be necessary to rely on the PVRR(d) method as a fallback.

I also wish to reiterate that the manner in which the Division seeks to apply the Schedule 38 method, *i.e.*, with annually restated values, is fundamentally incompatible with the structure of that method, which calculates long-term avoided costs after taking

[24] Rebuttal Testimony of Timothy M. Lenell, line 254.
[25] *Id.* at lines 302-305.

account of partially displaceable resources. I pointed out this problem with the Division's recommendation in my rebuttal testimony, and it was similarly noted by other parties, including the Company.[26]

**Q. ARE THERE ANY OTHER APPROACHES TO AVOIDED COSTS THAT COULD BE CONSIDERED?**

A. An alternative approach is for the avoided cost for the Program resource to be considered on an energy-only basis, *i.e.*, without assuming the displacement of a proxy resource. Under such an approach, the Program resource would not receive a credit for displacing capital costs, but neither would costs be attributed to it for lost PTCs. Also, without a displaced proxy resource, there would not be a basis for any party to assert that Program participants should have to compensate non-participants for the "lost value" of RECs.[27] In the absence of a credible IRP baseline, an energy-only avoided cost option warrants consideration.[28]

## III. TREATMENT OF RECS

**Q. DOES THE REBUTTAL TESTIMONY OF ANY PARTY ALTER YOUR OPINION THAT PROGRAM PARTICIPANTS SHOULD NOT BE REQUIRED TO COMPENSATE NON-PARTICIPANTS FOR THE "LOST VALUE OF RECS"?**

[26] Rebuttal Testimony of Daniel J. MacNeil, lines 166-196.
[27] Note that RMP witness MacNeil concurs with this latter point. *See* Rebuttal Testimony of Daniel J. MacNeil, lines 474-478.
[28] I note that in RMP's calculation of projected benefits and costs of the Program resource proposals that have been short-listed, which was provided to the Agency on December 8, 2025, the Company showed greater flexibility than what it proposed in its direct and rebuttal testimony, by providing a "no displacement" analysis, similar to what I am suggesting here as a potential alternative framework.

A. No. I addressed this topic at length in my direct and rebuttal testimonies and will not repeat those arguments here, except to note that since the filing of my rebuttal testimony, RMP has confirmed that no Schedule 34 customer has ever been charged for the lost value of RECs.[29] This confirmation reinforces my contention that the "lost REC benefit" 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 to date. Consistent with the ratemaking treatment for Schedule 32, 34 and 73 customers, Program participants should not be subject to a discriminatory "lost REC" penalty.

**Q. TURNING TO THE TOPIC OF REC RETIREMENT, WHAT IS YOUR RESPONSE TO RMP'S REBUTTAL TESTIMONY ON THIS ISSUE?**

A. RMP witness Eller argues that the Agency should not have an option to decline to retire the RECs generated by the Program resource, asserting that such an option would contravene the Program's clean energy goals.[30] In my rebuttal testimony, I explained at length why the Agency turning back the RECs to the system would *not* contravene the Agency's clean energy goals, particularly if the RECs were turned back out of economic necessity. I will not repeat that explanation here. I also explained how a hybrid option would facilitate the Agency's retirement of RECs in years in which there was no assumed displaced proxy plant, while allowing the Agency to make an economic decision as to whether or not to retire RECs in years in which Program participants would be required to purchase "lost RECs" from non-participants, if so ordered by the Commission. If the

[29] RMP Response to CREA Data Request 6.1(b), which is included in Agency Exhibit 8.1.
[30] Rebuttal Testimony of Craig M. Eller, lines 486-488.

Commission determines that Program participants must pay for the "lost value of RECs," then the hybrid option I described in my rebuttal testimony offers a reasonable and common sense path forward.

Mr. Eller also equates the Agency turning the RECs back to the system to selling "these attributes to third parties."[31] I find this characterization greatly misleading; indeed, it is entirely backward. Turning back the RECs would be done to *avoid a forced purchase* of the attribute *imposed* on the Agency simply because it had taken the initiative to support the development of a new renewable resource. Turning the RECs back would hardly constitute a "sale" to the benefit of the Agency, but rather the avoidance of an economic penalty.

Rather than opposing the ability of the Agency to decline to retire RECs, the Company, the Division, and OCS should be indifferent to it. RECs can only be counted once; they cannot be "double-counted" if the Agency declines to retire some. These parties have made great cause over the benefits of the supposed lost RECs that would accompany a displaced proxy resource. Given that predicate, I would expect these parties would be pleased, or at least untroubled, to have the Agency allow the Company to keep them.

These parties express concern that not retiring some of the RECs produced by the Program resource would be incompatible with the Program's mission. But as I explained in my rebuttal testimony, 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, which is entirely consistent with the Program's objectives,

[31] *Id.* at lines 482-483.

notwithstanding other parties' interpretations of what the Program's objectives should be. Moreover, 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 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. As I stated previously, 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. Providing such a hedge is fundamentally aligned with the Program's mission, irrespective of whether the RECs are retired by the Agency or donated back to the system.

## IV. WHETHER SCHEDULE 100 CAN BE A CREDIT

**Q. HAVE ANY PARTIES RESPONDED TO YOUR ARGUMENT THAT SCHEDULE 100 SHOULD BE A CREDIT IF THE ECONOMIC BENEFITS OF THE PROGRAM EXCEED THE ECONOMIC COSTS?**

A. The only other party to address this argument is RMP. Consistent with its response to discovery cited in my direct testimony, the Company opposes allowing Schedule 100 to ever be a credit, even if the economic benefits of the program were to exceed the economic costs. The Company offers three justifications for its position, each of which should be rejected by the Commission, as none of them are valid.

**Q. WHAT IS THE FIRST JUSTIFICATION THE COMPANY OFFERS FOR ITS POSITION?**

A. The first justification offered by the Company is that Schedule 100 cannot *logically* be a credit because if a renewable resource acquisition were able to provide incremental net benefits, then the Company (already) would have acted on its own accord to procure it for the benefit of the system.[32] In other words, the Company's primary argument is based on a logical truism – a truism that is patently untrue.

The Agency issued its own RFP for renewable resources. If selected, the Program resource at a minimum will allow the Company to avoid certain incremental energy costs. Whether those avoided energy costs are greater or lower than the power purchase price offered by the winning bidder is *unknown to the Company* at this time. The Company cannot truthfully claim that, by definition, it will always know and avail itself of the lowest cost resources for the system. In 2023 the Company suspended, then, in 2024, cancelled its 2022 All Source Request for Proposals for generation resources. In contrast, the Agency then went ahead with its own solicitation, with Commission approval. If the energy (and other) costs that the Program resource allows the company to avoid exceeds the power purchase price offered by the winning bidder, then all else being equal,[33] Schedule 100 should rightfully be a credit.

**Q. ARE THERE OTHER WAYS IN WHICH RMP'S PROPOSED RESTRICTION ON SCHEDULE 100 IS UNREASONABLE?**

A. Yes, as I discussed in my direct and rebuttal testimonies, RMP does not propose to levelize the net cost of the Schedule 100 resource, but rather proposes that Schedule 100 rates in each year would be based on the net cost for *that year*, as calculated at the time of contract

[32] Rebuttal Testimony of Craig M. Eller, lines 71-101.
[33] That is, after also accounting for all the other costs RMP intends to assign to the Program resource, *e.g.*, administrative, interconnection, RECs, etc.

execution and approved by the Commission. The implication here is that if avoided costs were to increase over time, the Schedule 100 charge could be greater in the early years of the Program and lower in the later years. Yet in the Program's later years, if the Schedule 100 calculation would provide benefits greater than costs, RMP would deprive participants of the credit associated with that later benefit, despite charging participants more in the early years of the project so as to not shift costs over time through levelization. If RMP is opposed to recognizing a Schedule 100 credit in years in which the Program's economic benefits exceed its costs, then the Company should at least be willing to levelize the Program benefits in the Schedule 100 calculation, so as to ensure that the net present value of Schedule 100 charges equals the net present value of Program resource costs over the life of the asset. The Company's position is inherently unfair and, although I am not an attorney, appears to be in direct conflict with statutory requirements that the Program not shift costs or *benefits* to non-participating customers.

**Q. WHAT IS THE SECOND JUSTIFICATION OFFERED BY THE COMPANY FOR NOT ALLOWING SCHEDULE 100 TO BE A CREDIT?**

A. The second justification relies on an overly narrow definition of "benefit" advanced by the Company. RMP maintains that:

> …the principal benefits of the program [are] 1) enabling incremental renewable generation beyond what would otherwise be acquired by the system, and 2) maintaining the ability for Program participants to make claims regarding participation in the Program and the incremental renewable generation it enables.[34]

[34] Rebuttal Testimony of Craig M. Eller, lines 106-110.

Conspicuously absent from the Company's understanding of Program benefit in this statement is the avoidance of incremental energy costs! After contriving this oddly narrow definition of Program benefits, RMP then claims that denying Program participants a Schedule 100 credit does not violate the statutory prohibition against shifting benefits to non-participating customers because it would not shift the two RMP-defined benefits to non-participating customers, while ignoring the implications of shifting the benefit of avoided energy costs to non-participants. The Company's failure to include avoided energy cost as a Program benefit in constructing its argument[35] ignores the statutory requirement that rates for participating customers "shall take into account *any* quantifiable benefits" to the utility and its customers (excluding those that do not directly affect the utility's cost of service).[36] Clearly, avoided energy cost is a fundamental quantifiable benefit of a Program resource. Therefore, it follows that avoided energy cost benefits may not be shifted to non-participants. RMP's attempt to narrowly define Program benefits to exclude avoided energy costs to support its argument is disingenuous and should be rejected by the Commission.

**Q. WHAT IS THE THIRD JUSTIFICATION OFFERED BY THE COMPANY FOR NOT ALLOWING SCHEDULE 100 TO BE A CREDIT?**

A. RMP maintains that a Schedule 100 credit would be a forced "payment by non-participants to participants beyond what they would otherwise pay for a competitively selected resource available in the market," and as such, "would represent an undue subsidy between

[35] RMP admits in discovery that avoided energy costs would be a benefit of the Program, and following this admission, relies on its first justification to defend its position. *See* RMP's Response to CREA Data Request 7.3, which is included in Agency Exhibit 8.1.
[36] Utah Revised Code § 54-17-904(4)(c). Emphasis added.

customers."[37] This characterization is wrong. Firstly, if Schedule 100 were a credit, non-participants would not be "paying" participants anything. RMP overlooks the fact that the Program is proposed to have a top-down rate design, which starts with current rates and then adjusts the current rate *up* to recover the incremental *costs* of a program, as well as *down* to credit its incremental *benefits*. Schedule 100 would only be a credit if incremental benefits exceed the incremental costs in a particular year. In such a case, participants would not receive a "payment" from anybody; rather, participants' all-in rates would simply be lower than they would be absent the Program resource. Such a situation is no different than what occurs in normal ratemaking when one class has lower average rates than another because the cost to serve it is lower. RMP's argument on this point is contrary to the principles of cost causation as applied in normal ratemaking and therefore should be rejected by the Commission. Instead, I recommend that the Commission confirm that if in a given year, the economic benefits of the program exceed the economic costs, Schedule 100 would not be subject to an artificial floor of zero as proposed by RMP, but rather would be permitted to be a credit.

## V. CONCLUSIONS

**Q. PLEASE PROVIDE A SUMMARY OF YOUR OVERALL CONCLUSIONS AND RECOMMENDATIONS IN THIS CASE.**

A. I offer the following overall conclusions and recommendations:

- It is reasonable to establish Program rates using a "top-down" rate design, as discussed in my direct testimony.

[37] Rebuttal Testimony of Craig M. Eller, lines 124-128.

- The Commission should not approve any Program resource valuation that assumes the Program resource would displace a proxy solar resource that would be eligible to earn PTCs. This assumption has a pronounced adverse impact on the Schedule 38 avoided cost calculation and is entirely improper in light of current Federal tax law. Yet both versions of the 2025 IRP being advanced by RMP for valuing the Program resource rely on this incorrect assumption.

- RMP maintains that it does not have an updated resource portfolio at this time. The Agency is not in a position to develop an alternative resource portfolio for RMP, but we do know that the proxy solar resources in the current portfolio will not be eligible for PTCs. Therefore, I conclude that the 2025 Utah IRP with the assumed displaced PTCs removed from the avoided cost calculation is the most reasonable, albeit imperfect, Schedule 38 platform available at the current time.

- The use of the PVRR(d) method to value the Program resource as proposed by WRA witness Boothman may be a necessary fallback option if the use of the Schedule 38 method for Program resource valuation turns out to be driven by meritless assumptions. The assertion by Division witness Lenell that use of the PVRR(d) method is more susceptible to inter-year subsidization than the Schedule 38 method is misplaced and should not be given any weight by the Commission.

- Another possible alternative is for the avoided cost of the Program resource to be considered on an energy-only basis, *i.e.*, without assuming the displacement of a proxy resource. Under such an approach, the Program resource would not receive a credit for displacing capital costs, but neither would costs be attributed to it for lost PTCs. Also, without a displaced proxy resource, there would not be a basis for any party to assert that Program participants should have to compensate non-participants for the "lost value" of RECs.

- Charging Program participants for "the lost value of RECs" as part of the resource valuation calculation should be rejected by the Commission. The "lost REC benefit" 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 to date. 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.

- Several parties argue that the Agency should not have an option to decline to retire the RECs generated by the Program resource, asserting that such an option would contravene the Program's clean energy goals. The Company's argument on this point, as well those of several other parties, should be rejected. In my rebuttal testimony, I explained at length why the Agency turning back the RECs to the system would *not* contravene the Agency's clean energy goals, particularly if the RECs were turned back out of economic necessity. I also explained how a hybrid option would facilitate the

Agency's retirement of RECs in years in which there was no assumed displaced proxy plant, while allowing the Agency to make an economic decision as to whether or not to retire RECs in years in which Program participants would be required to purchase "lost RECs" from non-participants, if so ordered by the Commission.

- The Commission should expressly require that if Program benefits exceed Program costs in any given year, then Schedule 100 should reflect a net credit to Program participants to ensure that the Program does not shift costs or benefits to non-participating customers. RMP's opposition to such a provision is contrary to the statute and the various justifications offered by the Company for its position are either factually inaccurate, disingenuous, or contrary to the principles of cost causation as applied in normal ratemaking.

- 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.

**Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?**

A. Yes, it does.