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** **Exhibit Division 2.0**

FOR THE DIVISION OF PUBLIC UTILITIES
DEPARTMENT OF COMMERCE
STATE OF UTAH

Direct Testimony of

Timothy M. Lenell

October 10, 2025

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ATTACHMENTS

DPU Exhibit 2.1, Resume of Timothy M. Lenell

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Timothy Lenell. My business address is 370 Main Street, Suite 325, Worcester, MA 01608.

Q. By whom are you employed and in what capacity?

A. I am employed by Daymark Energy Advisors Inc. (Daymark) as a Senior Consultant.

Q. Please summarize Daymark and its business.

A. Daymark provides integrated policy, planning, and strategic decision support services to the North American electricity and natural gas industries. Daymark serves a diverse clientele by providing consulting services to organizations involved with energy markets, including renewable energy producers, private and public utilities, transmission owners, energy producers and traders, energy consumers and consumer advocates, regulatory agencies, and public policy and energy research organizations. Our technical skills include cost allocation, rates and pricing, power market forecasting models and methods, economics, management, planning, energy procurement, contracting and portfolio management, and reliability assessments. Our experience includes detailed analyses of energy and environmental performance of electric systems, economic planning for transmission and distribution, and market analytics.

Q. Please summarize your education.

A. I have a bachelor's degree in economics from Northern Illinois University and a master's degree in economics from Iowa State University.

Q. Please describe your work experience.

A. I am an economist with over six years of economic analysis experience for the State of Nebraska. I have an additional five years of experience in rates and pricing for electric utilities. I worked for Omaha Public Power District (OPPD) in various roles, concluding my tenure as the Manager of Pricing and Rates before joining Daymark. At OPPD, I led the development of several technical studies including: the cost-of-service study (COSS), the load loss study, development of demand management programs, design of rates and renewable rider offerings, and a number of other associated studies.

Since joining Daymark, I have assisted clients in rate design, cost-of-service analysis, and revenue requirement analysis in Massachusetts and Louisiana, as well as other projects throughout the U.S. I have submitted direct testimony in support of Concordia Electric Cooperative's general rate case before the Louisiana Public Service Commission in Docket No. U-37586.

My experience and qualifications are described in more detail in my resume and selected testimony appendix, which is attached as DPU Exhibit 2.1.

Q. On whose behalf are you testifying?

A. The Division of Public Utilities (Division).

Q. Have you previously testified before the Public Service Commission of Utah?

A. No.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. Daymark was retained by the Division to assist in reviewing Rocky Mountain Power's (RMP or Company) Application seeking approval from the Public Service Commission of Utah (PSC or Commission) to implement the Community Clean Energy Program (CCEP or Program).

The Division's primary objectives in this docket are to:

- Ensure Program adherence to Utah Code section 54-17-904(4), which states:

  > The rates approved by the Commission for participating customers:
  >
  > (a) shall be based on the factors included in Subsection (2)(d) and any other factor determined by the Commission to be in the public interest;
  >
  > (b) may not result in any shift of costs or benefits to any nonparticipating customer, or any other customer of the qualified utility beyond the participating community boundaries; and
  >
  > (c) shall take into account any quantifiable benefits to the qualified utility, and the qualified utility's customers, including participating customers in their capacity as ratepayers of the qualified utility, excluding costs or benefits that do not directly affect the qualified utility's costs of service;

- Identify where modeling is opaque, inconsistent, or otherwise complex to understand and administer;
- Ensure the proposed annual rate adjustment and reporting requirements to the Commission provide the requisite information to demonstrate no cost shift has occurred or will likely occur to non-participants; and
- Evaluate if proposed safeguards adequately protect non-participants from cost shifting risk.

This direct testimony presents the results and the conclusions from that review.

Q. What information did you review in preparing your testimony?

A. I reviewed the following sets of information:

- RMP's Application Part I[1] and Part II,[2] Governance Agreement,[3] and Utility Agreement[4]
- The Direct Testimonies, exhibits, and workpapers of RMP witnesses Daniel J. MacNeil,[5] Craig M. Eller,[6] and Robert M. Meredith[7]
- The Direct Testimonies, exhibits, and workpapers of Community Renewable Energy Agency (CREA or Agency) witnesses Christopher Thomas,[8] Daniel E. Dugan,[9] Jeff Silvestrini,[10] and Kevin C. Higgins[11]
- RMP responses to data requests (DRs) submitted by all parties
- Utah Code section 54-17-904, the Community Clean Energy Program, and Community Renewable Energy Act under H.B. 411, and Commission Rule R746-314, Rules Governing the Community Renewable Energy Program

[1] Application to Implement Community Clean Energy Program Authorized by the Community Clean Energy Act (Application Part I).
[2] Application to Implement Community Clean Energy Program Authorized by the Community Clean Energy Act (Application Part II).
[3] Interlocal Cooperation Agreement Among Public Entities Regarding the Community Renewable Energy Program, 26b4b3_530d9ee5f75f40e6b2dda3179fe3240c.pdf.
[4] Community Renewable Energy Program Agreement between Rocky Mountain Power and Community Renewable Energy Agency, Town of Alta, Town of Castle Valley, Coalville City, City of Cottonwood Heights, Emigration Canyon Township, Francis City, Grand County, City of Holladay, Kearns Metro Township, Millcreek, City of Moab, Oakley City, Ogden City, Park City, Salt Lake City, Salt Lake County, Summit County, and Town of Springdale, https://www.utahrenewablecommunities.org/_files/ugd/f29e3f_b3505fc83690461f8831e0001703831c.pdf.
[5] Direct Test. of Daniel J. MacNeil (June 4, 2025).
[6] Direct Test. of Craig M. Eller (June 4, 2025).
[7] Direct Test. of Robert M. Meredith (June 4, 2025).
[8] Direct Test. of Christopher Thomas, Agency Ex. 3.0 (July 18, 2025).
[9] Direct Test. of Daniel E. Dugan, Agency Ex. 1.0 (July 18, 2025).
[10] Direct Test. of Jeff Silvestrini, Agency Ex. 2.0 (July 18, 2025).
[11] Direct Test. of Kevin C. Higgins, Agency Ex. 4.0 (July 18, 2025).

- The associated Docket No. 24-035-55, the Solicitation Process for the Community Renewable Energy Program (CREP)

Community Renewable Energy Agency Board Resolutions

Q. What are some of other analytical activities you engaged in while preparing your testimony?

A. I participated in meetings and discussions with Division personnel and certain Daymark coworkers, as well as attended CREA meetings.

III. SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. Please summarize your findings and recommendations.

A. Based on my review and the primary objectives of the Division as outlined above, I offer the following findings and recommendations:

Cost Estimation and Avoided Cost Findings

1. The Company's prudent and necessary start-up and administrative costs should be fully reimbursed consistent with Utah Code section 54-17-904(4)(b).
2. The target balance for Program reserves should be reduced from five years to two years to account for unwinding Program costs, which are short-term in nature and low risk for complications during termination.
3. The basis of using Schedule 38 for valuing the avoided cost is consistent with an Integrated Resource Plan (IRP)-linked, Commission-approved methodology for fairly compensating renewable resources for the value of the resource. However, Schedule 38 and the Program differ in their use of avoided costs. In the former, avoided cost is calculated to compensate Qualified Facility (QF) suppliers, whereas in the latter avoided costs are calculated to ensure that non-participants do not bear any costs or lose any benefits due to the Program. Consequently, the

Schedule 38 approach should be adjusted. The Company proposes adjustments to accommodate the difference in the policy objectives of the Program. My recommendations below outline the appropriateness of each adjustment when used in the current docket to better align the avoided costs of the developer resource with the policy objectives and the unique risks presented by the Program.

4. With respect to the process of transmission cost assignment, the process should follow this procedure: each transmission upgrade should be separately identified and categorized by the Company as either part of the IRP transmission plan (where the costs would go into rate base) or triggered by the Program resource. If part of the preferred portfolio but the Program resource requires an acceleration of the timing of the planned transmission upgrade, the Company should provide evidence of the incremental costs from the acceleration; otherwise, transmission upgrades within the IRP plan should not be directly allocated to the Program. If triggered by the Program resource, by default the costs should be assigned to Program participants if under the $1 million cap on transmission costs. If over the $1 million cap, and the Company wishes to still execute the power purchase agreement (PPA), as it indicated in a Division data request DPU 2.13,[12] then the Company should provide evidence of the quantifiable benefits and identify the portion that will be allocated to all customers versus Program participants. The process for demonstrating the network system benefits should be part of the annual prudency review requirements.
5. The inclusion of interconnection costs should be explicitly accounted for to ensure that the costs remain within the Program and are not borne by non-participants. There should be clear guidance and cost tracking methodologies to be able to address all use cases.

[12] *See* DPU Ex. 2.2, Company Response to Division Data Request 2.13.

6. The Company's inclusion of a Renewable Energy Credit (REC) valuation is consistent with ensuring costs and benefits are contained to Program participants and should be removed from the avoided costs given that the Utah Renewable Communities (URC) will retain the RECs.
7. The URC should not be offered the right to decline retaining and retiring the RECs as it contravenes the intent of the Program's clean energy goals.
8. The opportunity loss of REC revenues resulting from curtailment of renewables during periods of oversupply is not a direct expense affecting the Company's costs of service and should not be factored in the REC valuation for non-participants.
9. The REC valuation should be evaluated when the methodology is proposed, and the Division reserves the right to file additional testimony regarding the approach after the methodology is proposed.
10. The Company provides insufficient details regarding the price-policy scenarios and stochastic risk considerations, making it difficult to evaluate their reasonableness. These adjustments contain subjectivity and, while used often as an IRP-planning tool, do not seem to align with the intent to capture costs or benefits that only affect the utility's cost-of-service.
11. The avoided cost determination should be updated annually according to the most recent Schedule 38 avoided cost evaluation. Such updates would reduce the risk of dependence on one particular IRP for Program evaluation purposes.
12. If the avoided cost results are updated annually, the contract valuation estimates beyond the production cost study, stochastic-risk considerations, and price-policy scenarios diminish in importance and may be eliminated. More frequent updates by the Company than anticipated in the Application could increase Program costs associated with producing those results and should be incorporated into the Program's design.

13. The Division does not oppose the Company-proposed 12.5 years of resource reserve balance to backstop the Program as well as provide surety to the developers. However, I suggest that the resource reserve balance be separately evaluated for Company-owned resources since unwinding of the Program may be made more complicated with Company-owned resources than for third-party PPAs.

Rate Design Evaluation Findings

1. The Program rate should update annually to ensure the target balance is projected to be achieved over the annual period. A maximum accrual threshold of the reserve target balances both for program and resource reserve balances should be established, i.e., 12.5 years of net resource costs and 2 years of program cost for each reserve target. A maximum threshold would ensure that CCEP participants do not over contribute to cost recovery, particularly in early years when project commencement could be delayed.
2. The kWh charge as proposed provides the best cost recovery mechanism and a balanced approach between simplicity of design and matching cost recovery with cost incurrence.
3. The Company should acknowledge that if the $0.70 limit to the low-income surcharge is reached the credit will adjust accordingly so the low-income subsidy is not underfunded.

Annual Rate Adjustment, Reporting Requirements, and Program Administration Findings

1. Assuming the Program is approved, the elements that need to be reported to the Commission as part of the annual prudency review, such as the participation rates, renewable production, interest rates, program costs, etc., must be determined to ensure no cost shifts to non-participants.

2. The Program should consider including limitations on re-enrollment for program stability reasons. Rules should be established to restrict re-enrollment particularly if the final design results in the potential for negative prices during the wind-down phase.

The findings are presented according to the following sections:

1. Cost Estimation and Avoided Cost
2. Annual Rate Adjustment, Reporting Requirements, and Program Administration
3. Rate Design Evaluation

IV. COST ESTIMATION AND AVOIDED COSTS

Q. Please describe the cost estimation for the Program resource and Administration costs.

A. Commission rule R746-314-401(3)(o)[13] states that the Application must provide "an explanation of how non-participating customers and the utility will not be subject to any program liability or costs." Mr. Eller's testimony for the Company describes the two main sources of Program costs to be resource costs and administration costs.[14] To prevent any cross-subsidization of the Program from customers who opt-out, RMP proposed the inclusion of administration costs, which include startup costs and ongoing administration costs, and reserve fund for program costs; and resources costs, which include transmission and interconnection costs, REC costs, the contract valuation estimates beyond the production cost study, the resource cost itself net of benefits, and reserve fund for resource costs. Each of these costs is discussed below.

[13] Utah Admin. Code R746-314-401(3)(o) (2025).
[14] Direct Test. of Craig M. Eller at 12:242-49.

Q. Please describe the start-up costs and proposed recovery.

A. Start-up costs are largely related to the IT software, phone support during the initial opt-out period, and training of staff. It is important to acknowledge that start-up costs are incurred prior to commencement date and risk being stranded if the Program fails.

The Company acknowledges that it intends to reimburse these costs first with Program revenues and, in the event that the Program is approved but fails, would seek reimbursement from the Agency.[15] However, to best position the Program to ensure non-participating customers do not pay for these costs as directed by Utah Code section 54-17-904(4)(b), having start-up costs be recovered in the beginning of the program is appropriate to ensure recovery in a way that reduces the subsidy concern.

Q. Do you offer any recommendations regarding the start-up costs?

A. I would like to emphasize the statute's requirement in Utah Code section 54-17-904(4)(b),[16] which requires that the Program administration costs are fully recovered within the Program by participants. Start-up costs that are prudent and necessary should be accounted for in the Program's rates.

The largest start-up cost is the IT software development. The Company provides examples of these costs as "modifications to accommodate program charges and tracking."[17] This description is too brief, and in rebuttal testimony, the Company

[15] *Id.* at 13-14:271-82.
[16] "The rates approved by the commission for participating customers . . . may not result in any shift of costs or benefits to any nonparticipating customer, or any other customer of the qualified utility beyond the participating community boundaries . . . ."
[17] Direct Test. of Craig M. Eller at 12-13:255-59.

should explain how any allocable IT costs are solely attributable to the Program and not general IT enhancements used and useful elsewhere by the Company. If such investments are utilized by the Company for more than just the Program, the Program should be reimbursed for that portion based on proportional usage. This will require the Company to establish clear rules for allocation and Program reimbursements. Furthermore, if maintenance of the IT system for Program purposes is needed over the horizon of the Program that is beyond general IT maintenance, those costs should be added. Whether IT system costs are realized after start-up, and whether the functionality is used elsewhere should be accounted for in the annual reporting requirements to the Commission.

Q. Has consensus among the parties been reached with regard to the recovery of program start-up costs should the Program fail before full recovery?

A. My understanding at this point is that the parties have not reached a consensus.[18] As outlined in RMP witness Craig Eller's testimony, "[u]pon Commission approval to implement the Program, the Company will execute a contract with the Agency and Communities prior to incurring the start-up costs."[19] It is important that the Company not incur start-up costs until reaching an agreement with the URC to ensure that non-participants are not impacted by start-up costs if the Program fails. In addition, it is essential that Community Agreements are executed following Commission, Agency, and Company approval so that the Program rates are calculated using accurate participation rates.

[18] *See* DPU Ex. 2.2, Company Response to Division Data Request 2.3.
[19] Direct Test. of Craig M. Eller at 14:283-90.

Q. Please describe the on-going administration costs and proposed recovery.

A. Ongoing administration costs that will continue throughout the duration of the program include $150,000 in Agency legal and communication consultation, $153,750 for a URC program administrator, ongoing phone support and noticing, and a 1.5% escrow fee based on the balance of the reserve accounts. The Company notes that the escrow fee is subject to change depending on negotiations with the financial institution with which the escrow account would be opened.[20]

In addition to the actual cost of the Program, I observe that the Program costs represent a large percentage of the overall initial rate.[21] One of the primary reasons for this is the Company-proposed reserve fund balance target of 60 months. The 60-month reserve balance was proposed at the level that the Company is "comfortable with" to ensure all program administration costs were recovered should the Program fail.[22]

Q. Do you believe that 60 months of program reserve balance is required to ensure Program stability and protection from failure?

A. I believe that 60 months of program reserve balance is overly conservative. When the Division asked the Company to identify stranded costs that would result should the Program terminate, the Company responded that the five years of costs is needed as a backstop to ensure that the costs "already incurred and costs necessary to wind down the program are covered by program participants and do

[20] *See* DPU Ex. 2.2, Company Response to Division Data Request 2.30.
[21] *See* RMP Meredith Workpapers – Ann. Sch. 100 Updates Example.
[22] *See* DPU Ex. 2.2, Company Response to Division Data Request 2.22(6).

not impact non-participating customers."[23] Some of the costs, such as the escrow/trust and management fees, would continue until all balances are disbursed, and phone support would be needed to inform customers of the Program's termination. However, it seems unlikely that it would require five years to unwind the Program, and funds should be disseminated with timeliness. At the same time, having only 12 months of reserve provides too little protection against the short-term mismatches in revenue collections versus expenses should there be large fluctuations in participation rates.

A target balance reserve of two years would likely provide the ability to cover large deviations in Program participation. Furthermore, if the Program were to terminate, given that many of the exit costs, such as communication, would cease quickly, a two-year reserve balance seems more reasonable. A two-year reserve balance should adequately protect from large deviations from participation as well as provide the ability to recover termination costs should the Program cease. If there are concerns about specific types of costs that could cause large deviations, the Company should identify them more clearly to allow evaluation of an appropriate reserve balance.

Q. Do you believe the Full-Time Employee (FTE) Program Administrator position is required?

A. As previously stated, the Utah law requires that costs to administer the Program are not passed on to non-participants.[24] While I do not have specific guidance on

[23] *See* DPU Ex. 2.2, Company Response to Division Data Request 3.4(1).
[24] Utah Code Ann. § 54-17-904(4)(b).

the salary level and position required to administer the Program, one FTE does not seem unreasonable to administer the Program given the complexities involved in tracking costs for annual reporting requirements.

Q. Please describe the Company's estimation for net resource costs.

A. The resource cost represents the cost of acquiring the clean energy resource, e.g. the PPA or Company resource. Program project bids were due July 10, 2025, and there was a total of 15 bids.[25] The solicitation process is discussed in Docket No. 24-035-55. After the PPA is executed, the resource costs net of the avoided cost will be used to determine the Program rate under Schedule 100.[26] The avoided cost methodology is based on a Schedule 38 evaluation approach. Being linked to the IRP, Schedule 38 represents a consistent and well-established Commission-approved approach for the basis of valuing the avoided cost resources in Utah. However, Schedule 38 and the Program differ in their use of avoided costs. In Schedule 38, the avoided cost determination is used to compensate QF suppliers. In the Program, the avoided cost is used to ensure that non-participants do not bear any costs or lose any benefits due to the Program. Consequently, when Schedule 38 methodology is used in the present docket, adjustments should be made to better align the avoided costs of the developer resource with the policy objectives and the unique risks presented by the Program. The Company Application states there are four limits to the Schedule 38 methodology that require modification including: (1) transmission services costs, (2) interconnection costs,

[25] Information shared during the 7/14/2025 CREA Board meeting.
[26] Direct Test. of Robert M. Meredith at 3-4:50-71.

(3) REC values, and (4) the contract valuation estimates beyond the production cost study.[27] These adjustments to the Schedule 38 methodology seek to account for the fundamental difference between the purpose of Schedule 38 and the CCEP. Schedule 38 is a valuation model intended to provide fair compensation for a QF. The CCEP is a community clean energy program to fund incremental renewables and is intended to be self-insulated to ensure no costs or benefits are passed to non-participating customers. Thus, in the deviation from Schedule 38, the basis for deviation should be to ensure self-containing costs and benefits within the Program's participating customers. Each adjustment is discussed next.

Q. Please describe the Company's procedure for transmission costs.

A. After a contract is selected, the Company will submit a transmission service request (TSR) to PacifiCorp to designate it as a network resource. If transmission resources are not available, the cost of the upgrade will be provided and if it exceeds $1 million, the resource may be removed from the Program. According to the Company, the $1 million threshold represents a *de minimis* amount that will allow for streamlining the procurement process.[28] The Company acknowledges that if the $1 million threshold is exceeded, the PPA may still be executed "[t]o the extent a mutually agreeable solution can be identified that protects non-participating customers."[29] Furthermore, the Company also acknowledges that "transmission costs would not be attributed to a Schedule 100 resource if the associated transmission upgrades are included in PacifiCorp's long-term

[27] Direct Test. of Daniel J. MacNeil at 4:71-77.
[28] *See* DPU Ex. 2.2, Company Response to Division Data Request 2.13.
[29] *Id.*

transmission plan."[30] The Company also states in response to Division data request DPU 5.1 that "[i]f an upgrade was previously part of the preferred portfolio and is accelerated as a result of the TSR, the incremental cost would only reflect the acceleration, and not the costs that were previously expected, as those costs provided interconnection and/or transfer benefits."[31]

Q. Do you support the $1 million cost threshold?

A. Yes, the $1 million threshold is a reasonable threshold to delineate between minor upgrade costs and those material enough to require a study to determine whether future projects would benefit from the upgrade. In its response to Division data request DPU 5.1, the Company states:

> Because PacifiCorp is not proposing to comprehensively reoptimize the resource portfolio as part of its analysis of Schedule 100 resources, it is unlikely to be possible to directly identify the potential value of future resources making use of expanded interconnection capability. Absent a transmission upgrade appearing in the original portfolio, PacifiCorp is not proposing to impute a benefit from increased interconnection capability.[32]

If above the $1 million threshold, the Company proposes to proceed only if a mutually agreeable solution can be identified that protects non-participating customers. I support this approach as it ensures, in the absence of demonstrable system benefits, that costs will be borne by participating customers. Any allocation to non-participating customers through system-wide benefits would require additional reporting requirements by the Company.

[30] *See* DPU Ex. 2.2, Company Response to Division Data Request 2.15.
[31] *See* DPU Ex. 2.2, Company Response to Division Data Request 5.1.
[32] *Id.*

Q. How could the Company address transmission costs above $1 million?

A. If the Company selects a resource that would require a major investment above the $1 million threshold, the Company should be required to re-optimize its resource portfolio to evaluate if the excess capacity provides system benefits. The purpose of this re-optimization would be to determine the quantifiable benefits that would be attributable to all customers versus the portion attributable to Program participants.

As part of the annual review of the cost inclusions, I suggest that the Company identify any transmission upgrade as either part of the IRP transmission plan, where the costs would not be attributed exclusively to Program participants, or triggered by the Program resource. If part of the preferred portfolio but the Program resource requires an acceleration of the timing of the planned transmission upgrade, the Company should provide evidence of the incremental costs from the acceleration; otherwise, transmission upgrades within the IRP plan should not be directly allocated to the Program.[33] If triggered by the Program resource and under the $1 million threshold, by default the costs should be assigned to Program participants. If the necessary transmission upgrade is over the $1 million limit and the Company wishes to still execute the PPA, the Company should provide evidence of the quantifiable benefits and identify the portion that will be allocated to all customers versus Program participants. The process for demonstrating the network system benefits and incremental costs exclusively allocated to Program

[33] *Id*.

participants requires Company-provided evidence sufficient to allow the Commission to ensure no cost shift to non-participants occurs.

Q. Please describe the Company's inclusion of interconnection costs.

A. Interconnection costs are costs incurred to physically connect the resource to the transmission system and are governed by a Large Generator Interconnection Agreement (LGIA) filed with the Federal Energy Regulatory Commission. These costs could include substation upgrades, line extensions, and related investments. The QFs, to which the LGIA applies, would typically pay these costs under Schedule 38,[34] and the costs are not netted against the avoided cost valuation. Consistent with the statutory mandate to include all costs, the interconnection costs should be recovered within the Program and not otherwise paid by all customers including non-participants. The CCEP resource is confined to participants to ensure that the benefits and costs are allocated solely to participants. The resource displaces the opportunity for it to benefit other customers in the future since the benefits are attributable to only Program participants.

Q. How should the Company address interconnection costs within a generation interconnection cluster?

A. If the resource is located in a shared cluster, the Company must determine the incremental interconnection costs from the Program resource relative to other projects. The Company has not provided detailed discussion around the treatment

[34] Schedule No. 38. Original Sheet No. 38.10. *See* Process for Negotiating Interconnection Agreements. Procedures.

of these types of use cases. The treatment of interconnection costs under Schedule 100 should be clarified in cases of mixed interconnecting project clusters. By doing so, the Company will establish clear guidance for cost tracking and methodological allocation to ensure that there is no cost-shifting to non-participants.

Q. Please describe the Company's rationale for excluding REC valuation from the avoided cost.

A. The Company's IRP does not assign a value for RECs.[35] Company witness Mr. MacNeil states in his testimony that while not assigned a value, the retention of the RECs by participants necessitates a need to determine a valuation and account for RECs in the avoided cost through a reduction in the assumed cost avoidance.[36] This is different from the Schedule 38 evaluation, where the utility pays the full avoided cost for energy but retains the RECs.[37]

Since the participants in this case retain the RECs, as the URC has expressed desire to do,[38] the Company maintains that the value of the RECs should be subtracted from the Program benefits.[39] The placeholder for the value of the RECs is assumed to be $10/MWh.[40] These un-avoided costs (or uncaptured benefits) are added to the Program beginning in the year of operation.

[35] Direct Test. of Daniel MacNeil at 7:148-52.
[36] *Id.* at 7-8:153-57.
[37] *Id.* at 7:142-47.
[38] *See* DPU Ex. 2.2, Company Response to Division Data Request 2.16(1).
[39] Direct Test. of Daniel MacNeil at 7-8:153-57.
[40] Direct Test. of Robert M. Meredith at 3-4:50-71.

In addition to the REC premium, Mr. MacNeil discusses the incremental REC cost related to curtailment of renewable resources during periods of oversupply.[41] This is separate from the REC premium but not currently given a specific valuation in the Program's REC premium estimate of $10/MWh.

Q. Should the URC be able to decline the right to retire the RECs?

A. This seems to contravene the intent of the Program as the energy would not be classified as clean energy if the RECs are not retained by the community.[42] While net 100% renewable energy by 2030 is not mandated, the Agency states that it is the goal being pursued by the Agency and in line with resolutions adopted by 18 of the 19 member communities.[43] To credibly achieve any renewable energy goal, the participating communities must retain and retire the RECs.

Q. Do you agree that an adjustment is required to the Schedule 38 valuation to account for the URC retaining the RECs?

A. Yes, the benefit of the RECs remains within the Program, and thus the REC valuation should be separately accounted for since Schedule 38 assumes fully bundled power. The communities must maintain the RECs to be able to claim any clean attributes. Non-participants receive the reduced system energy purchases and reduced capacity requirements, but they do not benefit from the RECs.

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[41] Direct Test. of Daniel MacNeil at 8:158-69.
[42] H.B. 411 Community Renewable Energy Act.
[43] Direct Test. of Christopher Thomas, Agency Exhibit 3.0. at 21:395-405.

Q. Do you agree with the incremental REC cost consideration related to curtailment of renewables?

A. Curtailment of renewables would result in less REC revenue. However, this is not an incremental cost to the Company's cost of service. Rather, curtailment simply reduces the number of RECs produced. In addition, calculating this counterfactual opportunity cost would be hard to quantify, as Company testimony notes: "the prevalence and magnitude of negative market prices is highly uncertain."[44] The lost value of RECs from curtailment is not justifiable from a direct cost perspective to non-participants and should not be included.

Q. How has the Company indicated it will determine the REC valuation?

A. The Company has indicated that REC prices will be determined based on resource type, location, vintage, and Commercial Operation Date (COD), but does not propose a specific methodology for determining the value at this time.[45] The Company indicates that the estimated lost revenue that non-participating customers would have received will likely reflect recent REC purchase and sales information.[46] While historical REC sales would be observable and auditable, the lack of clarity on the methodology provides no means to ascertain if the Company's proposed methodology is acceptable. A methodology for determining the fair REC valuation and the reporting requirements has yet to be developed. For this reason, it is unclear whether the Company's methodology ensures no cost shifting to nonparticipants.

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[44] Direct Test. of Daniel MacNeil at 9-10:184-201.
[45] *See* DPU Ex. 2.2, Company Response to Division Data Request 2.16(4).
[46] *See* DPU Ex. 2.2, Company Response to Division Data Request 2.16(2).

Q. Is some modification to the valuation estimate for life of the contract beyond the production cost model study horizon required?

A. The Company's testimony notes the contract length is likely to extend beyond the study horizon, and that a simple valuation extrapolation may not suffice.[47] In its response to the Division's data request DPU 2.17, the Company further explains that instead of valuation based on an extrapolation at inflation beyond the horizon, it may use a three- to five-year approach to reduce the impact of any outliers and balance transient conditions.[48] The Company does not provide a specific methodology for valuing the resource in that manner but proposes to identify the approach it settles on.

Q. What alternative considerations would you propose for the contract length issue?

A. If the Company annually updates the avoided cost benefit to the most recent quarterly Schedule 38 valuation, there is no need to address the contract valuation estimates beyond the production cost study because of this regular valuation update.

Assuming that the Application is approved with a fixed avoided cost methodology as the Company has proposed, the concept of determining a value for the extension of the contract beyond the production cost modeling horizon seems like an appropriate consideration to ensure benefits are realized fully through the Program. However, due to a lack of detail presented by the Company, the Division

[47] Direct Test. of Daniel MacNeil at 10-11:202-21.
[48] *See* DPU Ex. 2.2, Company Response to Division Data Request 2.17.

reserves the right to provide additional testimony when the approach is determined, at which point it can better speak to the method, timing, and other considerations.

Q. How does the Company seek to incorporate the price policy scenarios?

A. Rather than the Official Forward Price Curve (OFPC) that Schedule 38 utilizes in the avoided cost determination, the Company expects to provide results under a weighting of the MN (medium natural gas/no federal CO_2 regulation), LN (low natural gas/no federal CO_2 regulation), and HH (high natural gas/high CO_2 costs) price-policy scenarios.[49] The Company's rationale underlying the deviation from the OFPC is that the weighted approach is how the Company justified non-QF resource acquisitions.[50] This would also insulate the calculation from the volatility of the forward-price curves of the OFPC. In any case, the Company acknowledges that it has not selected a weighting for price-policy scenario results.[51]

Q. Do you agree with the deviation in price policy scenario?

A. The Company believes the IRP prudency test used to justify non-QF resource acquisitions is a better approach, but it provides little context for the deviation from the existing OFPC incorporated in Schedule 38. The weighted price-policy scenario as described by the Company would provide a long-term resource valuation. However, the statute requires that the Program exclude "costs or benefits that do not directly affect the qualified utility's cost of service."[52] The weighted approach suggested by the Company would be based on planning

[49] Direct Test. of Daniel MacNeil at 13:273-77.
[50] *Id.*
[51] *See* DPU Ex. 2.2, Company Response to Division Data Request 2.18.
[52] Utah Code Ann. § 54-17-904(4)(c).

assumptions, but the Company has not provided sufficient evidence explaining why it believes that the weighted approach better reflects the cost to serve over the existing OFPC method. Relying on these blended, projected amounts gives a measure of certainty to the Company and the URC but leaves other ratepayers to account for the difference between those projections and actual results in a given year.

If the concern for the OFPC method is the extrapolation of results, once again, this could be addressed by having the avoided cost updated annually. In such a case, the rate would consistently be updated with the most recent market data based on the utility's cost of service.

To ensure the methodology results in a more accurate reflection of the cost to serve than the OFPC method, the Company would need to provide its rationale for weighting and documentation of inputs to ensure alignment with its other IRP assumptions and demonstrate the cost measures. Since these are not provided within the filing, the Division reserves the right to provide additional testimony when an approach is proposed.

Q. Why does the Company suggest the consideration of stochastic risk?

A. The Company suggests the need to account for stochastic risk that can arise from market and system conditions.[53] Variables such as load deviations and unit performance are factors it would use to determine if the resource is likely to result in lower costs in the long term. The Company acknowledges that the framework for considering the stochastic results would be prepared in the same manner as

[53] Direct Test. of Daniel MacNeil at 14-15:295-323.

the 2025 IRP, but that could lead to different interpretations given that the IRP focuses on a portfolio-wide solution rather than resource specific, as Schedule 100 does.[54]

Q. Is including stochastic risk consistent with the avoided cost methodology?

A. While I cannot determine the appropriateness of this approach given the lack of methodological details, I maintain that a better way to capture potential future outcomes is to have the avoided cost update annually. Stochastic risk assessment represents a change from the avoided cost methodology. Stochastic scenarios represent distributed outcomes of hypothetical futures that have not historically been incorporated in Schedule 38 evaluation. While the Company argues that including a stochastic risk assessment provides an enhancement to the avoided cost value, the inclusion creates additional complexity to ensuring consistent, reliable, and deterministic cost measures that can be evaluated and audited as part of the annual prudency review of costs. Furthermore, the suggestion that the stochastic results could deviate from the 2025 IRP framework introduces additional complexity that would need to be separately evaluated.

Q. Is Schedule 38 the appropriate basis for cost avoidance in the Program?

A. Despite the concerns I discuss below, the Schedule 38 methodology as adjusted by the Company Application provides an appropriate inclusion of transmission costs, interconnection costs, and REC valuation to accommodate the unique characteristics of the Program. The adjustment for stochastic risk, policy scenarios, and contract risk is better addressed by having the avoided cost methodology

[54] *See* DPU Ex. 2.2, Company Response to Division Data Request 2.19.

update annually. It is important to highlight that while the CCEP is based on the Schedule 38 avoided cost methodology, there are key differences between Schedule 38 and the CCEP valuation. The Schedule 38 method, which is a Partial Displacement Differential Revenue Requirement (PDDRR), was approved in Docket No. 03-035-14 to compensate QFs under the federal Public Utility Regulatory Policies Act.[55] The PDDRR methodology was not statutorily required as the methodology for the Program and differs in intent as described above. This allowed the Company to make adjustments based on the determination that costs and benefits must be incurred solely by Program participants.

The Program rate is a function of the full cost of the clean energy resource net of costs the utility avoids. The Company is proposing that the basis for the CCEP is Schedule 38, with modifications to account for the full burden on the utility to secure the clean energy resource.

Q. Does the Company propose that the avoided cost would update annually?

A. The Company does not propose that the avoided cost be updated as part of the annual reconciliation process.[56] This would put significant importance on the IRP filing and associated impact on the PDDRR valuation for Schedule 38 resources at the execution of the PPA. Speaking to the variation that has been recently provided in avoided cost valuation, such as in Schedule Nos. 37 and 38, the Division provides the following context in its Initial Comments in Docket No. 25-035-T03, "[t]he Division notes that the avoided cost calculation is highly dependent

[55] *Application of PacifiCorp for Approval of an IRP-based Avoided Cost Methodology for QF Projects Larger than One Megawatt*, Docket No. 03-035-14.
[56] *See* DPU Ex. 2.2, Company Response to Division Data Request 2.22(7).

upon the current IRP filings, resulting in model assumptions that are not always vetted at the time of filing for avoided cost updates."[57] This highlights an important consideration since the IRP does not seek to calculate a specific long-term avoided cost of Schedule 100 and does not explicitly take into account such impacts. Importantly, slight assumption changes can result in a different set of resource selections that may have significant impacts on cost avoidance calculations.

Q. Does an annual update provide a better valuation for avoided cost benefits?

A. Yes. While Schedule 38 provides a Commission-approved valuation for determination of the avoided costs of renewable resources, if updates to the avoided costs element of the Schedule 100 resource are not made, the Program's avoided cost determination could result in overreliance on the most current IRP assumptions.

Alternatively, as I propose, the avoided cost could be updated in conjunction with the most recent Schedule 38 valuation. By doing so, this issue could be resolved. Furthermore, rather than having to determine the weighted average of the LN, MN and HH price-policy scenarios, the OFPC will be in line with current market conditions.

By suggesting the avoided cost be updated annually, I acknowledge that some additional administrative costs would most likely be incurred that would need to be added to the Program since it was not anticipated in the Application filing. However, the result would provide a better match of Program benefits and costs.

[57] *Rocky Mountain Power's Proposed Tariff Revisions to Electric Service Schedule No. 37, Avoided Cost Purchases from Qualifying Facilities*, Docket No. 25-035-T03, Division's Initial Comments (July 18, 2025) at 3.

Q. Do annual updates provide better adherence to the no cost shifting mandate?

A. As noted, the Division's foremost objective is adherence to the statutory mandate that rates may not result cost shifting to non-participating customers. The volatility in the Schedule 38 evaluation over time shows how market conditions, system conditions, and IRP planning can influence results. To ensure that benefits and costs are not shifted to non-participants, the annual Program rate setting should incorporate the most recent Schedule 38 valuation.

Q. Describe the Company's rationale for its proposed resource reserve balance target?

A. As explained, the resource costs are netted against the avoided cost calculations. The Company's reserve balance target is 150 months of the net cost without supplement.[58] In response to the Division's data request DPU 2.10, the Company stated that the 150 month target was based on an estimate of what "a developer may be comfortable with as a backstop to supply the resource of the Community Clean Energy Program," noting that this could be negotiated by the developer.[59]

Q. Is surety to the developer the only reason to require the resource reserve balance?

A. No, the resource reserve balance also protects non-participants if participation erodes or the Program terminates. Therefore, it represents not just a credit

[58] Direct Test. of Craig Eller at 18:368-74.
[59] *See* DPU Ex. 2.2, Company Response to Division Data Request 2.10.

assurance to developers but serves as the backstop to protect non-participants from bearing costs should the program terminate.

Q. Is the total balance of the resource reserve the only factor influencing the Program rate?

A. While the reserve balance amount is one factor to consider, another is the timing of achieving the target resource reserve balance. The Company states that the rationale is to provide a backstop to the developer should the Program fail while the resource is being constructed.[60] This rationale seems defensible; however, many renewable projects experience delays. A survey by Berkley Lab in 2024 found that "[a]pproximately one-third of wind and solar siting applications submitted in the last five years were canceled, while about half experience delays of 6 months or more."[61] I recommend that as part of the annual review of the Program the Company report the commencement dates and any adjustments made to ensure that the resource reserve balance does not exceed the proposed target balance.

Q. What is the impact of the resource reserve balance on the Program rate?

A. The combination of the 12.5 year reserve balance and requirement to reach a target reserve 1 year prior to commencement has a significant impact on the initial program rate. The rate of $0.006132/kWh (before low-income subsidy) in the first year of the Program is over 10 times the assumed rate of $0.000515/kWh during the maintenance-phase years.

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[60] *See* DPU Ex. 2.2, Company Response to Division Data Request 2.22 part 4.
[61] Berkley Lab. Energy Markets and Policy, Survey of Utility-Scale Wind and Solar Developers Report, https://emp.lbl.gov/publications/survey-utility-scale-wind-and-solar.

This front loading is significant to the customer's experienced rate impact. In the initial year of the Program, the Program rate has a bill increase across customer classes between 4.8%-7.5%. The maintenance phase's bill increase was between 0.4% and 0.8% as modeled in Company witness Meredith's Workpapers.[62]

Q. What would be the initial Program rate if the reserve balance was reduced?

A. The Company did provide an alternative scenario of the rates if the Program reserve was set at 12-month target and the resource reserve was set at 60-month target.[63] Under this scenario, the bill increase of the initial year of the Program rate across customer classes was between 2.1% to 4.0%, or nearly half of what is proposed in the Company's Application. This emphasizes the importance of determining the appropriate amount to backstop the Program.

Q. Could the Program participation rate be impacted by the reserve balance?

A. The lack of uniformity in the recovery of costs could increase the opt-out rate and encourage customers to forego signing up for the initial years of the Program. Since the Company has proposed no limits on the number of times a customer can sign up for or exit the Program,[64] customers could elect to wait to enroll until the rates are cheaper in the maintenance phase. However, the Agency expressed that it desires manageable bill impacts over acceleration to net 100% clean energy in Resolution 25-08,[65] and suggests securing smaller resources to ensure manageable bill impacts.[66]

[62] *See* RMP Meredith Workpapers – Ann. Schedule 100 Forecast Model – Bill Impacts.
[63] *See* DPU Ex. 2.3, Company Response to Division Data Request 3.4, Attachment.
[64] *See* DPU Ex. 2.2, Company Response to Division Data Request 1.4, part 7.
[65] CREA Board Resolution 25-08.
[66] Direct Test. of Christopher Thomas, Agency Exhibit 3.0 at 20:380-94.

Q. Does the Program reserve balance as presented in the Application result in any equity concerns through the three-phases?

A. In the draw-down phase, the rate is projected to be negative as the reserve balance is returned to participants. This presents a perverse incentive for customers to enter the Program during the final years.

If the rates remain as projected in the three phases, there should be limits to customer re-enrollments because of the rate differential incentives identified above. At a minimum, it would be prudent to restrict re-enrollment during the wind-down phase or years in which the net Program rate is projected to be negative. Not doing so may disrupt revenue planning, create opportunistic re-entry, and risk the interest of long-standing customers.

Q. Should the reserve balance target be the same whether the Company or a third party owns the Program resource?

A. The ability of RMP to exercise the option to own the resource would complicate assumed backstop provisions. It may be more difficult for the Company to unwind the Program since the resource is within its own portfolio and could require a different reserve balance. The Company acknowledged that it will only offer a resource option if CREA bonded for the full value of the transaction.[67] Given the unique complexities, I recommend that the resource reserve balance be separately evaluated for Company-owned resources, as unwinding of the Program may be made more complicated with Company-owned resources than if supplied through third-party PPAs.

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[67] *See* DPU Ex. 2.2, Company Response to Division Data Request 2.1.

V. ANNUAL RATE ADJUSTMENT, REPORTING REQUIREMENTS, AND PROGRAM ADMINISTRATION

Q. Describe the annual rate adjustment filing procedure proposed in the Application.

A. Commission Rule R746-314-401(3)(f) requires the Program application to include:

> a description of the proposed process for periodic, not more than annually, rate adjustment filings, including a proposed schedule or dates for such filings, which filings shall include:
>
> (i) an accounting of program expenses;
> (ii) the projected costs and revenues for the following year of the program; and
> (iii) any proposed changes to program rates, termination fees, tariffs, or other associated program charges[.]

The Company's proposed annual filing process not only accounts for program costs but will also provide a calculation of the revenues required to meet target reserves and associated changes in the rates and charges. Program revenues are influenced primarily by participant load and enrollment levels. In addition to variations in load and enrollment, the degree to which actual costs of the Program resource deviate from projected costs, and the Program's administrative costs would also impact the annual reconciliation. The annual filing process updates the actual data through April of the filing year. The Program rate will be effective beginning November 1 of the filing year through October of the following year.

Q. Does the Company anticipate an annual adjustment filing each year?

A. While the RMP workpapers make it clear that the Program rate in Schedule 100 can be revised upward or downward based on these underlying factors, the Company has not indicated that it intends to revise the Program rate each year if revenues cover all costs.[68] Excess revenues will go into the reserve funds and reduce future rate needs, but whether the annual rate is updated appears to be at the discretion of the Company.

Q. What should trigger the annual rate adjustment to the Program rate?

A. The Program rate should be adjusted to ensure that the target reserve balance is maintained. This includes both under and over recovery. In relation to over recovery, the Company stated in its response to Division data request DPU 2.8 that it objects to restricting the reserve fund balance to a level determined to be sufficient until a resource PPA is executed.[69] However, it further clarified that the Company would be open to restricting the reserve fund balance after the resource is selected to the target balance reserve.[70] Thus, after the resource is selected the target reserve can be established and the Program rate and adjustments to the annual mechanism can ensure that the target reserve balance is appropriately maintained.

Indexing the Program rate to the reserve fund target balance level as proposed by the Company seems sound, insofar as there is a cap on the maximum accrual amount or a bandwidth of the amount that can be carried forward before returning to participants through lower rates. This would ensure that the Program rate is not systematically over-recovering from Program participants while achieving the necessary balance to ensure protection to non-participants.

[68] *See* DPU Ex. 2.2, Company Response to Division Data Request 2.7.
[69] *See* DPU Ex. 2.2, Company Response to Division Data Request 2.8.
[70] *See* DPU Ex. 2.2, Company Response to Division Data Request 3.3.

Q. In addition to the annual rate adjustment what information should be annually reported to the Commission?

A. If the Program were to be approved, there should be rules and transparency about the elements that must be reported to ensure that there is no cost shifting to non-participants. Recognizing there are a variety of outstanding issues to reconcile, at a minimum, the annual filing to the Commission should include:

- Enrollment participation counts and load by community, by class, low-income participation, and number of opt-outs and opt-ins. Comparisons to original projection levels and any major deviation should be explained.
- Program Resource details including: size, COD (with updates as appropriate), PPA price and terms (redacted and unredacted), as well as actual resource performance versus initial expectations.
- Cost tracking and itemization of actual costs: interconnection and transmission costs (and the allocation of costs between Program participants and all customers, with associated supporting details), start-up costs, ongoing administration costs, and net resource costs. In addition, the items for which cost determinations have not been made—REC valuation, contract horizon risk, price policy scenarios and stochastic risk assessment—should be provided with associated supporting details.
- For the preceding year and projected for the following year, the rate changes under Schedule 100, as well as reserve fund balance and target levels.

The Company's filing has indicated that a number of these items will be tracked and reported, but the level of detail has not been provided. Detailed accounting should be provided and confirmed to ensure no-cost shifting to non-participants, and the Company should provide such details in its next round of testimony.

Q. Are there any remaining Program elements without consensus?

A. The Company identified a number of Program elements that remain without consensus including: the return of Program start-up costs should the Program fail before recovery, the valuation of resources (as discussed above), and termination provisions of the Program resource PPA assuming termination of the Program itself.[71]

Q. Do you have recommendations regarding these unresolved elements?

A. Since resolution to these issues has not been provided, I do not have any findings or recommendations apart from emphasizing that these Program elements must ensure protections for non-participating customers.

Q. Should the Program be approved with these details unresolved?

A. I recommend that the Commission withhold approval until these unresolved issues are reasonably addressed and the Commission is assured of sufficient protections for non-participants.

VI. RATE DESIGN EVALUATION

Q. Please describe the proposed rate design for Schedule 100.

A. The overall rate design proposed by the Company is a two-part rate. The energy charge would recover the net resource cost to fund the target reserves for both the program and net resource costs. A separate fixed charge supports participation by low-income individuals.

The Company projects the following rates as provided in Table 1.

[71] *See* DPU Ex. 2.2, Company Response to Division Data Request 2.3.

Table 1. Schedule 100 Rates as Presented in Forecast Model[72]

Phase	Participant Rate $/kWh	Low-Income Surcharge $/customer-month
Build Up Phase: Year 1-2	0.006132	0.11
Build Up Phase: Year 3-4	0.003040	0.06
Maintenance Phase: Year 5-17	0.000515	0.01
Draw-Down Phase: Year 18-24	-0.001032	-0.02*

*Company acknowledged this should be capped at zero.[73]

Q. How will the energy charge fund both the program reserve balance and the resource reserve balance?

A. The energy charge is proposed as a single line item on the bill. However, since the resource reserve fund is separate from the reserve fund for administration, the rate is proposed to be separately tracked.[74] The tracking of the revenues for the resource and program reserve funds must be reported as part of the annual reporting to the Commission since the revenues for Program administration costs will be paid to the Company for administration while revenues for net resource will be paid for Program resources.[75]

[72] *See* RMP Meredith Workpapers – Ann. Schedule 100 Forecast Model – Summary.
[73] *See* DPU Ex. 2.2, Company Response to Division Data Request 4.1.
[74] *See* DPU Ex. 2.2, Company Response to Division Data Request 2.26.
[75] *Id.*

Q. Does the statute dictate the form of recovery?

A. The statute does not state the form of the recovery of the charges but should be guided by typical cost of service and rate design principles. Program costs, which are typically driven by the number of customers, would typically be recovered on a fixed recovery basis, while resource costs should properly be recovered through a kWh charge since the driver of the costs is the production of intermittent renewable energy.

However, there is already a fixed charge component to support the low-income provision, and an additional fixed fee for Program costs may be confusing to customers. The major driver of the cost of the Program is resource costs, and the Company has proposed a $/kWh charge to recover both the Program administrative and net resource costs. I support the Company's proposal for a fixed charge to cover low-income participation and have all other costs recovered via the $/kWh energy charge. The $/kWh charge matches cost recovery with cost incurrence and recognizes the driver of the Program cost as renewable project production.

Q. Please describe the low-income surcharge.

A. The low-income surcharge design is based on two Board resolutions, 22-11 and 22-12. The subsidy for low-income customers will be in the form of a surcharge of no more than $0.70 per customer per month.[76] For low-income participants, the monthly bill credit will not exceed $7.00.[77] An important feature is that the low-

[76] CREA Board Resolution No. 22-11.
[77] *Id.*

income assistance is contained within the Program and does not impact non-participating customers.

Q. Does the Company anticipate being near the $0.70 per customer per month surcharge limit?

A. In the Company's Application, the surcharge is projected to be $0.11 per customer per month.[78] Even under the alternative scenario provided, which models low participation by communities, the rate was projected to rise to only $0.19 per customer per month. Thus, the $0.70 limit to the surcharge anticipates covering all the costs to provide credits for low-income assistance.

Q. Does the Company discuss what will result if the subsidy reaches the $0.70 per customer per month cap?

A. No, however, it should be noted that the schedule does state "[c]redits provided are subject to the availability of Program funds."[79] Should the limit in the surcharge create a gap in any coverage, the credit should be reduced to ensure that the low-income assistance is not underfunded, and this may be the Company's intent. In response to Division data request DPU 5.3, the Company stated it does intend to enforce the $0.70 surcharge limit.[80] I believe that the Company should explicitly acknowledge that if the $0.70 surcharge limit is reached as envisioned by the Communities' low-income plan the Program credits will be reduced commensurately in order to ensure the assistance program is fully funded.

[78] *See* RMP Meredith Workpapers – Ann. Schedule 100 Updates Example.
[79] Application Part I, Attachment G at 3.
[80] *See* DPU Ex. 2.2, Company Response to Division Data Request 5.3.

Q. How does the $7 credit cover low-income participants?

A. At the current rate of $0.006132/kWh provided in the initial year of the filing, a low-income participant will have no bill impact for the first 1,141 kWh used. In the Company's model, the average monthly kWh for residential usage is assumed to be 637 kWh. Consequently, at the projected rate, most low-income participants would be covered through the credit.

Q. Are there any other low-income provisions of the tariff that are unique?

A. In addition to the bill credit of up to $7, those qualifying for low-income assistance are not subject to the termination fee. In addition to having those on Schedule 3, the Low-Income Lifeline Program - Residential Service, automatically qualify for the low-income bill credit, the Agency established the Low-Income Plan Committee for the 19 participating communities to facilitate low-income assistance. As part of the Committee Action Plan, the participating communities have engaged with approximately 100 organizations that interface with low-income populations to implement education and outreach best practices related to engaging these communities in the Program.[81] I support these provisions.

Q. Do you have any additional findings regarding the low-income plan?

A. In the initial filing, the Program did not adequately address what will occur when Program rates are positive (e.g. the Draw Down phase). Initially, in the workpapers provided by Company Witness Meredith, the rate during the wind-down period was projected to be -$0.02/month which implies that the low income participants will be

[81] Direct Test. of Daniel E. Dugan, Agency Exhibit 1.0 at 11-12:210-42.

charged instead of subsidized.[82] In response to Division data request DPU 4.1, the Company acknowledged that they do not intend the low-income surcharge to become a credit to all customers[83] and provided an updated workbook with no low-income surcharge during the wind-down phase.

I would suggest the Company explicitly acknowledge that the Program's low-income credit cannot reach a level below $0.

Q. Are there other Program charges?

A. In addition to the low-income and Schedule 100 rate charges, there are termination fees. Termination fees were developed by CREA and provided to the Company.[84] The proposed termination fees[85] are as follows:

- Residential Schedule 1, 2, 2E, 3, and Non-Residential Schedule 23, 7, 10: $30 flat fee
- Non-Residential Rate Schedule 6, 6A, 8, 9A, and 9: $6 per Average kW
- Non-Residential Rate Schedule 11, 12: $0.96 per kW
- Non-Residential Rate Schedule 15, 22: $0.96 per Average kW

Q. How were the termination fees determined?

A. As cited in the Company's filing, the termination fee schedule was created to protect low-income participants and discourage frequency of entry and exit to the Program while not being punitive to the point of discouraging participation in the first instance.[86]

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[82] *See* RMP Meredith Workpapers – Ann. Schedule 100 Forecast Model – Summary.
[83] *See* DPU Ex. 2.2, Company Response to Division Data Request 4.1.
[84] *See* DPU Ex. 2.2, Company Response to Division Data Request 1.4(6).
[85] Application Part I, Attachment G at 6.
[86] *Id.* at 8-9.

Q. Did you suggest any revisions to the tariff provisions regarding termination fees?

A. As already noted, the Company has not proposed limits to the number of times a customer can enroll in or exit the Program. I suggest that the Commission consider limitations on re-enrollment for Program stability to discourage any gaming or opportunistic reentry into the Program based on potential rate differentials over the life of the Program.

Q. Does this conclude your testimony?

A. At this time, yes.