Division Exhibit 2.2

Company Response to Division Data Requests in the Testimony of Timothy Lenell

DPU Data Request 1.4

In reference to Attachment G: Proposed Tariff Changes to Implement Program:

(1) Application Section G, page 8, the Application states that "…Schedule 100 contains placeholders for the Program rates because the Program does not yet have an acquired resource to base its rates on." When will RMP acquire the proper resources to base its rates on?

(2) Application Section G, page 8, the Application states that "…Schedule 100 contains specific dates that are illustrative and based on the Company's estimated timeline for Program implementation." What is the source of the estimated timeline? Is there a contingency timeline if there are substantial delays?

(3) Attachment G, page 1, does Clean Energy Resource, as defined within Schedule 100, meet the Utah State Legislature's criteria as set forth in Utah Code Section 54-17-902? Is there any intent to solicit anything other than generating resources (e.g., energy efficiency or demand response) through a PPA?

(4) Attachment G, page 2, is the exit notice process the same as the opt-out notice process or different? If different, please provide as much detail as is known.

(5) Attachment G, page 3, regarding the $7 per month cap discussed in the "Low-Income Assistance" section, please provide the justification for this number.

(6) Attachment G, page 6, please provide the derivation of the termination fees by rate schedule, and all the supporting details regarding the termination fee. Are there measurable costs supporting the fee? Are there risks associated with non-residential customer classes terminating that do not apply for residential customer classes terminating?

(7) Application G, page 8, regarding the termination fee rationale of setting the fee high enough to prevent frequent joining and exiting, are there any proposed tariff provisions that would limit the number of times a customer can join and exit?

Response to DPU Data Request 1.4

(1) In accordance with Public Service Commission of Utah (UPSC) Rule R746-314-402, the Company must obtain approval of a competitive solicitation process in order to solicit program resources. The Company filed for approval of the solicitation process in Docket No. 24-035-55, which is pending UPSC approval. Once approved, the solicitation will be initiated to determine the

resource and associated costs for informing the rates in the proposed Electric Service Schedule No. 100 (Schedule 100). At this time, the Company does not know exactly when the resource will be acquired.

(2) The dates referenced in Schedule 100 are based on the Community Clean Energy Program (Program) implementation timeline in Section M of the Company's Application filed on January 24, 2025 in this proceeding:

Application filed with PSC	1/24/2025
PSC approval	8/31/2025 estimated
Ordinance deadline	11/29/2025 90 days, 54-17-903(3)
Prep period for noticing/billing system	4/28/2026 5 months
Implementation Date (first notice sent)	4/29/2026 next day
Noticing period ends	6/28/2026 60 days, 54-17-905(1)(b)(i)
Program revenues begin	6/29/2026 next day
End of three billing cycles no term fees	7/7/2026 100 days 54-17-902((8)(b)
First Annual Filing	7/1/2027 1 year, 3 mos
Program rate change effective (if needed)	11/1/2027 4 months

The Company developed the anticipated schedule based on statutory deadlines, if applicable, and the Company's experience for dates that are not governed by statute or UPSC Rule. Delays in a particular milestone, such as UPSC approval, would require the remaining dates to adjust accordingly.

(3) Yes. The definition of "Clean Energy Resource" in Schedule 100, provided as Attachment G, to the Application filed on January 24, 2025 was copied word-for-word from Utah Code Section 54-17-902(3). The statute allows the Program to utilize energy efficient and sustainable technology as defined in Section 54-17-902(3)(b). The Company included the full definition of "Clean Energy Resource" in Schedule 100 to be consistent with the statutory language. While the Program resource will be ultimately determined through the solicitation that is pending UPSC approval in Docket No. 24-035-55, it is the Company's understanding, based on discussions with the Community Renewable Energy Agency (CREA), that the Program intends to procure a generating resource, not energy efficiency or demand response programs.

(4) The Opt Out Notice process is the process by which an eligible customer elects to not participate in the Program. The process for a customer to opt out is described in Attachment L to the Company's Application (page 2 for non-residential customers and on page 5 for residential customers). As described, a customer can opt out through three methods: (1) Online (logging into their account and opting out), (2) By Mail (detaching and filling out a form that will be mailed to each eligible customer), or (3) By Phone (calling the Company's customer service line). The Exit Process is the process by which a customer who is a participating customer leaves the Program. A participating customer may leave the Program by contacting the Company's customer service line to notify the Company it wishes to leave. At that time, the Company can advise the customer what termination fees, if any, will apply.

(5) The Company objects to this request to the extent is seeks information from CREA that is not within the Company's possession. Subject to and without waiving the foregoing objection, the Company response as follows:

The proposed $7.00 Low Income Assistance Credit was developed by CREA and provided to the Company as part of the communities' proposals provided in Attachment J to the Company's Application. The Company does not possess the justification for the amount.

(6) The Company objects to this request to the extent is seeks information from CREA that is not within the Company's possession. Subject to and without waiving the foregoing objection, the Company response as follows:

The proposed Termination Fees in Schedule 100 were developed by CREA and provided to the Company. The Company does not possess the justification for the amounts. The Company has not assessed the difference in risk to the Program of a non-residential customer terminating versus a residential customer.

(7) The Company has not proposed limits on the number of times a customer could enter and exit the Program.

DPU Data Request 2.1

Under what circumstances would RMP exercise an option for a qualified utility to own the clean energy asset? Is it solely RMP's option, or would the Community Renewable Energy Agency or the projects solicited also need to approve that option? When would the option be exercisable? How would such a transaction be memorialized? In RMP's view, would these be rate-based assets thereafter?

Response to DPU Data Request 2.1

Rocky Mountain Power (RMP) will only offer a resource option if the Community Renewable Energy Agency (CREA) is willing to bond the amount that is needed for recovery and return on investment needed to own that clean energy asset. No, it is not solely RMP's option; it has to be agreed upon with CREA, and the Public Service Commission of Utah (UPSC) will need to approve that executed agreement. The resource option is exercisable only if RMP offers it, CREA agrees to it, and the UPSC approves the transaction. Such a transaction will be offered in a form similar to a power purchase agreement (PPA) over a potential 20-year or 25-year term that only serves the participants of the Utah Clean Energy Program. The transaction will be bonded such that should the Utah Clean Energy Program fail, the bond will cover the recovery and return on the investment that RMP made to support the Utah Clean Energy Program. No, the asset would not be rate-based as the backstop is the bond for the full value of the transaction to ensure nonparticipants are not impacted by the cost of the asset acquired for the Utah Clean Energy Program.

DPU Data Request 2.3

Craig M. Eller Testimony Questions - Reference Direct Testimony of Craig Eller, pg. 3, ln. 57-60. Please describe in detail what aspects of the Program the Parties did not achieve consensus on? Do any of these issues relate to either the Governance Agreement, Utility Agreement or program model PPA(s) used to contract resource? If so, please describe and refer directly to implicated provisions.

Response to DPU Data Request 2.3

Key elements where consensus has not yet been achieved include:

(1) Treatment of start-up costs to implement the program is currently not covered in any agreement. PacifiCorp has assumed inclusion in rates to be recovered in the first year of the program from participants. A separate agreement was in draft form for recovery from the Utah Community Renewable Energy Agency (CREA) should the program fail but is yet to be agreed upon.

(2) Valuation of the resources where the Company has assumed the Company will value the resource at acquisition of the power purchase agreement (PPA) and maintain that value, both contract price and avoided costs value of the resource, over the term of the PPA.

(3) Termination provisions of the program resource PPA; PacifiCorp has assumed that the resource PPA terminates upon termination of the program.

These elements do not relate to the Governance Agreement or the Utility Agreement.

25-035-06 / Rocky Mountain Power
July 10, 2025
DPU Data Request 2.7

DPU Data Request 2.7

Craig M. Eller Testimony Questions - Please refer to the Direct Testimony of Craig Eller, pg. 15, ln. 314. Under what conditions would an annual updating or a requirement for a rate adjustment not occur as frequently as annually? Regardless, what are the parameters or reasoning for allowing the rate to remain at current levels beyond an annual update? Is there a maximum time allowed between updated rate adjustments?

Response to DPU Data Request 2.7

Rates could remain unchanged in an annual cycle should revenue collected cover all costs of the Community Clean Energy Program.

Under U.C.A § 17-907(1)(a), “[t]he qualified utility may make a rate adjustment filing, not more than annually[.]” Therefore, the Company may adjust rates no more than once a year. Otherwise, the Act does not provide a maximum time allowed between updated rate adjustments.

DPU Data Request 2.8

Craig M. Eller Testimony Questions - Reference Direct Testimony Craig Eller, page 16-17, lines 344-352, please answer the following questions:

(1) What is the anticipated gap of time between the commencement date and in-service date?

(2) Given the supply constraints and delays in project integration seen in the industry, what is the maximum level allowed for the resource reserve and administrative reserve fund balance? If no maximum level is currently determined, would the Company be open to restricting the reserve fund balances to a level determined to be sufficient?

Response to DPU Data Request 2.8

(1) PacifiCorp objects to this request to the extent it seeks information from PacifiCorp that is not within the Company's possession. The developer builds the resource that determines in-service date, and the resource for the Community Clean Energy Program has yet to be identified. Subject to and without waiving the foregoing objection, PacifiCorp responds as follows:

The forecast model, "Meredith Workpaper – Sch. 100 Forecast Model.xls," assumes of two years.

(2) No maximum balance has been determined as the reserve fund value that needs to be accumulated is subject to valuation of the resource, which has yet to be identified. No, currently, the Company is not open to restricting the reserve fund balances. The resource that will determine the reserve fund, which needs to be accumulated to backstop the program, has yet to be identified for valuation. As such, the Company objects to restricting the reserve fund balance to a level determined to be sufficient until a resource power purchase agreement (PPA) has been executed, where resource valuation is then available to determine a reasonable maximum level.

25-035-06 / Rocky Mountain Power
July 10, 2025
DPU Data Request 2.10

DPU Data Request 2.10

Craig M. Eller Testimony Questions - Reference Direct Testimony Craig Eller, page 18, lines 370-374 regarding the sufficient reserve amounts, please answer the following:

(1) How were the balances of 150 months for the share of the PPA and 60 months of the program costs determined?

(2) Were other reserve fund balance levels considered?

Response to DPU Data Request 2.10

(1) The 150 months for the share of the power purchase agreement (PPA) was an estimate of what a developer may be comfortable with as a backstop to supply the resource of the Community Clean Energy Program but ultimately can be negotiated by the developer. The 60 months program costs is a backstop estimate that the Company is seeking for administrative costs..

(2) Over the development of the proposed program, the Company considered all aspects of the program in many ways. However, the reserve fund balance levels proposed in Mr. Eller's direct testimony was the most reasonable level to propose.

DPU Data Request 2.13

Daniel J. MacNeil Testimony Questions - Reference Direct Testimony Daniel MacNeil, page 5, line 95 – 103. Explain why a PPA could be terminated if upgrade costs exceed $1 million dollars? How was this threshold established and decided upon? If a program resource(s) were to face this situation but agreed to pay all costs including those that may exceed that threshold, under what reasoning would the Company terminate the PPA and forego the opportunity to add to transmission rate-base?

Response to DPU Data Request 2.13

In accordance with PacifiCorp's Open Access Transmission Tariff (OATT), network upgrade costs triggered by a designated network resource (DNR) request submitted to PacifiCorp Transmission by PacifiCorp's energy supply management (ESM) department for a power purchase agreement (PPA) is paid by PacifiCorp and not the developer. Consequently, network upgrade costs associated with such a request become part of transmission rate base, and the associated costs would be charged to retail customers. These costs cannot be known before the designated resource request is studied by PacifiCorp Transmission, and these studies cannot commence until the PPA is executed. Because these costs are unknown at the time the PPA is signed and considering that these costs can be sizeable, limits are set in the PPA to protect retail customers from the risk of unexpected transmission upgrade costs identified as part of DNR request. This safeguard provides an opportunity for PacifiCorp to reconsider the PPA in light of the cost associated with the DNR request.

The $1 million threshold is a de-minimus amount relative to the lifetime costs and benefits of a typical utility-scale resource procured through a request for proposals (RFP) or bilateral negotiations and is intended to avoid complicating the procurement process if required system modifications are minor.

To the extent a mutually agreeable solution can be identified that protects non-participating customers, PacifiCorp would not need to terminate the PPA.

DPU Data Request 2.15

Daniel J. MacNeil Testimony Questions - Reference Direct Testimony Daniel MacNeil, page 6-7, line 127 – 141, regarding the share that Utah retail customers pay, do all retail customers pay a portion of the transmission costs or are the costs contained within Schedule 100? Are there any ancillary benefits to the upgrades of the transmission facilities that will be considered in planning?

Response to DPU Data Request 2.15

PacifiCorp is not proposing any changes to the allocation of transmission costs associated with Schedule 100 resources. The cost of network upgrades to PacifiCorp's transmission system are allocated to all retail customers as well as to Open Access Transmission Tariff (OATT) customers. The proposed Schedule 100 resource valuation accounts for the portion of the transmission costs allocated to retail customers.

PacifiCorp's long-term resource evaluation includes two aspects of transmission upgrades:

- Transfer capability: the ability to move more energy between transmission areas modeled in the Integrated Resource Plan (IRP) topology (e.g. Figure 8.3 in the 2025 IRP:

  https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2025-irp/2025_IRP_Vol_1_Utah.pdf

- Interconnection capability: the ability to interconnect more resources within a given transmission area.

For additional discussion, please refer to pages 189-192 in Volume I of the 2025 IRP. Note: transmission costs would not be attributed to a Schedule 100 resource if the associated transmission upgrades are included in PacifiCorp's long-term transmission plan.

25-035-06 / Rocky Mountain Power
July 10, 2025
DPU Data Request 2.16

DPU Data Request 2.16

Daniel J. MacNeil Testimony Questions - Reference Direct Testimony Daniel MacNeil, page 7-8, lines 143-157, please answer the following questions:

(1) What does the Company do with the RECs from the projects described here? Specifically, how do Company REC sales from non-Company owned renewable projects benefit the Company's ratepayers under Utah's voluntary RPS? Does every dollar of REC revenue translate to a dollar reduction in retail revenue requirements?

(2) If the IRP does not estimate the value for RECs, what is the basis for the valuation assumed in the valuation model?

(3) If set to zero currently, will REC values potentially be assigned in future years? If so, how?

(4) Will separate REC prices be determined based on resource type, location, or other factors? If so, please describe the methodology for doing so.

Response to DPU Data Request 2.16

(1) The Company assumes that the renewable energy credits (REC) from the projects that support the Utah Clean Energy Program will be retired, as the Utah Renewable Community have expressed interest in that approach. Company REC sales from non-Company owned renewable projects benefit ratepayers because RECs are sold by the Company where a buyer can be found and any Utah's allocation of REC sales revenue are provided to Utah customers through the REC Balancing Account (RBA).

(2) PacifiCorp's 2025 Integrated Resource Plan (IRP) did not include an estimated value for RECs for resources selected in the Utah, Idaho, Wyoming, and California (UIWC) jurisdictional analysis. As part of its Schedule 100 resource valuation, PacifiCorp will provide an estimate of the projected REC value that non-participating customers would otherwise have received during the portion of the Schedule 100 resource contract term in which the value is based on a renewable resource. This estimate is likely to reflect PacifiCorp's recent REC purchases and sales information and may include other information about REC supplies and demand.

(3) As described in the Company's response to subpart (1) above, actual revenue from sales of Utah-allocated RECs is passed back to retail customers through Schedule 98.

(4) Yes. However, PacifiCorp does not have a specific methodology at this time. REC prices primarily vary based on the vintage (the year of generation),

whether they are for forward period, current year, or prior year, and the resource's commercial operation date (COD). In general, REC prices for specific projects are higher, and technology type and location may be valued more highly by an individual purchaser. Bundled REC pricing typically treat a pool of resources interchangeably: it may exclude certain resource types that are considered less valuable, such as large hydro, and resources may only need to deliver within the western interconnect.

DPU Data Request 2.17

Daniel J. MacNeil Testimony Questions - Reference Direct Testimony Daniel MacNeil, page 10-11, lines 204-221, please specify how the Company will provide valuation for resources past the study horizon? Please describe in detail the methodology that is being considered to provide an "accurate determination of the incremental costs" when a sizeable portion of a resources contract term is outside the study horizon.

Response to DPU Data Request 2.17

PacifiCorp does not have a specific methodology for valuing resources beyond the horizon. The Schedule 38 methodology assumes escalation at inflation beyond the horizon, and that resources with value solely based on proxy resource fixed costs would be accurately represented with inflation alone. However, most resources have some energy or production cost dispatch component in their valuation. For example, as a result of differences between the proxy resource generation profile and the Schedule 100 resource generation profile. Because production cost modeling results for different years represent a variety of conditions over time, as a result of the timing of expiring resources and additions, rather than extrapolating based on a single year, PacifiCorp would typically escalate based on three to five years of results at the end of the horizon. The escalation is intended to reduce the impact of outlier conditions, and the specific number of years might be adjusted to account for variations that are sustained beyond the study horizon (e.g. a thermal resource retirement) or to balance transient conditions (e.g. a delay between mid-year contract expirations and January 1 proxy resource additions). To the extent the interaction between the Schedule 100 resource and the current preferred portfolio warrants different treatment than what can be achieved with inflation or extrapolation as described above, PacifiCorp would identify the most appropriate calculation as part of the valuation.

25-035-06 / Rocky Mountain Power
July 10, 2025
DPU Data Request 2.18

DPU Data Request 2.18

> **Daniel J. MacNeil Testimony Questions -** Reference Direct Testimony Daniel MacNeil, page 14, lines 286-288, has the company selected a weighting for the MN, LN, and HH scenarios? If so, specify in detail the basis of the weighting and how this was developed.

Response to DPU Data Request 2.18

> The Company has not selected a weighting for price-policy scenario results.

25-035-06 / Rocky Mountain Power
July 10, 2025
DPU Data Request 2.19

DPU Data Request 2.19

Daniel J. MacNeil Testimony Questions - Reference Direct Testimony Daniel MacNeil, page 15, line 323, does the Company intend to mirror the 2025 IRP risk-adjusted value methodology? If not, please describe rationale for not doing so.

Response to DPU Data Request 2.19

PacifiCorp's 2025 Integrated Resource Plan (IRP) risk-adjustment methodology is the current starting point for representation of stochastic results, and the series of modeling results produced as part of that analysis would likely to prepared in the same manner as the 2025 IRP. Given the emphasis in the IRP on portfolio-wide results, rather than resource-specific results, the results for an individual Schedule 100 resource might warrant a different interpretation. For example, consideration of the relative risk-related impacts of proxy resources and the Schedule 100 resource.

25-035-06 / Rocky Mountain Power
July 10, 2025
DPU Data Request 2.22

DPU Data Request 2.22

Robert M. Meredith Testimony Questions - Reference Direct Testimony Robert Meredith, page 3-4, lines 51-71 regarding the forecast assumptions, please answer the following:

(1) Is there any escalation included in the administrative costs? If so, please provide detail as to what the escalation is and how it was determined. If not, please explain why not?

(2) How close is the 5% interest rate to actual rates the company receives?

(3) Please provide some insight into the level of reasonable fluctuation that might be expected with regard to start-up costs. Would the Company be comfortable with establishing an acceptable level of bandwidth for recovery? When actual costs are determined, will details of deviations be explained if greater than a certain level?

(4) Please elaborate why the reserve balance must be achieved 1 year before the resource's commercial operation date?

(5) Please provide context for the need for 12.5 years of the cost of the PPA in excess of the avoided cost value upfront. What level of opt-out would be required in the first year of the program to make the reserve balance deplete to a level that will constitute a termination of the program resource?

(6) Please provide context for the need for 5 years of the cost of the administration upfront.

(7) Will benefits such as avoided cost value be updated annually? If so, please describe the process for annually updating the avoided costs value. Was an escalation of the avoided cost values assumed over time?

Response to DPU Data Request 2.22

(1) The forecasted administrative costs assumption that starts the calculation has been escalated to 2026 dollars. Work paper "Meredith Workpaper – Sch. 100 Forecast Model.xls" does not assume further escalation.

(2) The interest rate of five percent is comparable to the average cost of long-term debt included in the Company's recently approved general rate case (GRC), Docket No. 24-035-04.

(3) The start-up costs to be billed to the communities are subject to fluctuation of customer number changes and postage costs increases. The Company is not able to predict either component.

The start-up costs proposed to be billed to Utah Community Clean Energy Program participants through Schedule 100 are subject to fluctuations of how many customers call into the 800 number, time it takes to answer the customers' questions on the Utah Community Clean Energy Program and potential software development cost increases. The Company is not able to predict either component; the presentation in work paper "Eller Workpaper – Program Costs_URC.xlsx" are based on assumptions provided by Utah Renewable Community (URC) percentages of customer participation, and potential phone contact assumption.

No. The Company must ensure that all costs of the Utah Community Clean Energy Program are recovered from the Communities and the participants of the Utah Community Clean Energy Program. Under U.C.A. § 54-17-904(4)(b), "[t]he 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[.] To be clear, the law does not allow costs or benefits to impact non-participants or the qualified utility.

(4) Achieving the reserve balance a year before commercial operations date (COD) provides the developer with a backstop assurance that part of the resource will be paid for should the Utah Clean Energy Program fail while the resource is being constructed.

(5) The 12.5 years of resource reserve balance is an initial perspective of what a developer may require to be comfortable to execute a power purchase agreement (PPA) that will provide clean energy to participants of the Utah Clean Energy Program. The reserve level to be maintained must cover 12.5 years of value for the first 12.5 years before it is allowed to deplete below the stated level; the reserve must be replenished should the level fall below the 12.5 year of reserve required within the 12.5 years of the first year of commercial operations of the resource or termination could be triggered.

(6) The five years of administrative reserve balance is what the Company is comfortable with to ensure all Utah Clean Energy Program administrative costs are recovered should Utah Clean Energy Program fail.

(7) No. Avoided costs will be determined at the execution of the PPA and will not be updated annually.

25-035-06 / Rocky Mountain Power
July 10, 2025
DPU Data Request 2.26

DPU Data Request 2.26

> **Robert M. Meredith Work paper Questions -** The kWh charge does not seem to be unbundled in rate design (admin versus resource costs not split in the .6132 cents per kWh charge). How will the Company determine if the revenues are resource or administrative reserve revenues to determine the sufficiency of the reserve balances? Are the revenues unbundled in the Company system and not in the billing to the customer? If not unbundled, what is the rationale for two separate reserve funds?

Response to DPU Data Request 2.26

> Please refer to the workpaper supporting the direct testimony of Company witness, Robert M. Meredith, work paper "Meredith Workpaper – Annual Schedule 100 Forecast Model" for the separate rates for administrative costs (Community Renewable Energy Agency (CREA) Rate) and resource costs (Reserve Fund CREA Rate).
>
> Revenues for the CREA Rate and the Reserve Fund CREA Rate will be shown as a single line item on the bill and tracked separately through a spreadsheet. The rationale for separate reserve funds is that revenues affiliated with the CREA Rate will be paid to the Company for administration, whereas revenues for the Reserve fund CREA Rate will be paid for resources.

25-035-06 / Rocky Mountain Power
July 10, 2025
DPU Data Request 2.30

DPU Data Request 2.30

Craig M. Eller Work paper Questions - Regarding program costs, please explain the note on the 1.5% management fees within the Eller Workpapers that says “this is not a statutorily-required cost.”

Response to DPU Data Request 2.30

The Company assumes that the question relates to the “Escrow / trust setup and management fees (assume 1.5% applied to Program Subtotal Cost)” line that has a subscript reference to stated “this is not a statutorily-required cost” and answers as follows:

The 1.5 percent assumption for fees is an estimate of what the escrow fees could cost on the balance of the reserve accounts; the reserve accounts are to be opened by the Community Renewable Energy Agency (CREA) and is subject to change depending on negotiation results with the financial institution that the escrow accounts are opened with.

DPU Data Request 3.3

Refer to Response to DPU Data Request 2.8, please clarify if the Company objects to restricting the reserve fund balance after the resource is selected. Would the Company be open to restricting the reserve fund balance after the resource is selected and the costs are known to the targeted revenue balance (i.e. 12.5 years)? If the Company does not intend to adjust the annual rate when the reserve balance is projected to achieve the Company's target, please explain why.

Response to DPU Data Request 3.3

No, the Company does not object to restricting the reserve fund balance after the resource has been identified, valued, and a power purchase agreement (PPA) has been executed.

As stated in the Company's response to DPU Data Request 2.8(2), "as such, the Company objects to restricting the reserve fund balance to a level determined to be sufficient until a resource power purchase agreement (PPA) has been executed, where resource valuation is then available to determine a reasonable maximum level."

Until the Company can determine what the cost of the PPA is, the Company cannot determine what the value of the 12.5 years of PPA is. Therefore, the Company cannot determine a sufficient reserve fund balance until the PPA is executed.

If the reserve balance is projected to achieve the Company's target, there will be no need to adjust the annual rate.

25-035-06 / Rocky Mountain Power
August 4, 2025
DPU Data Request 3.4

DPU Data Request 3.4

Refer to Response to DPU Data Request 2.10, please answer the following:

(1) Given that much of the program costs are to support ongoing noticing that would cease if the Program terminated, why is 5 years of all program costs needed as a backstop? Please explain, by line item according to Eller Workpaper, II – Program Costs, the stranded costs items.

(2) If the resource reserve balance was reduced to 60 months and the program reserve balance was reduced to 12 months, what would be the impact on rates in Schedule 100? Please provide for all three phases – Build-Up, Maintenance, and Draw-Down Phase.

Response to DPU Data Request 3.4

(1) Five years of program costs is needed as a backstop to ensure that should the program terminate early, the program ensures that all costs already incurred and costs necessary to wind down the program are covered by program participants and do not impact non-participating customers.
In reference to "Eller Workpaper, II-Program Costs", "Table D. Program Expenses Summary", the stranded costs items include: (7) Noticing – ongoing (12 months), which is needed to cover any termination noticing for the program to participating communities; (8) Noticing – paper exit confirmation, which includes sending out confirmation of participants' exit from the program; (10) Agency Costs, a program administrator which PacifiCorp understands the Agency intends to hire; (11) URC Program Administrator at the Utility, which will administer the program and potentially address program termination activities to wind down the program once terminated; (13) phone support – annual refresher training, which provides annual training for the call center; (14) Phone Support – ongoing, which will be utilized to address any calls from participating customers with regards to the program terminating; and (17) Escrow / trust and management fees, which will continue until all balances are disbursed to terminate the program.

(2) Please refer to Attachment DPU 3.4 which provides forecast program rates during each phase if the resource reserve balance is reduced to 60 months and the program reserve balance is reduced to 12 months.

25-035-06 / Rocky Mountain Power
August 5, 2025
DPU Data Request 4.1

DPU Data Request 4.1

Refer to the RMP Meredith Workpapers - Ann Sch 100 Model 6-4-25, during the Drawn-Down Phase (2043-2049), the low-income surcharge becomes negative, which appears to mean that low-income participants will be charged, please see the Forecast Assumptions tab row 29. On the Forecast CREA Model tab, the charges seem to indicate that the low-income surcharge becomes a credit to all customers and a charge to low-income, see row 37 versus row 43 in years 2043 through 2049. The price before low-income assistance is -$0.001032, but the credit grows to -$0.001062. Is this intentional in design or a spreadsheet error? Please elaborate.

Response to DPU Data Request 4.1

No, this is not intentional. The Company does not intend the low-income surcharge to become a credit to all customers. Please refer to Attachment DPU 4.1 which provides a revised workbook.

DPU Data Request 5.1

Given the $1M transmission cost threshold discussed in DPU Data Request 2.13, does the Company believe that most transmission upgrades would be minor? For costs over $1M, does the Company intend to quantify if system-benefits would occur that would be paid by non-participants? If so, please describe the method for determining the system benefits of transmission network upgrades.

Response to DPU Data Request 5.1

Every transmission service request (TSR) is unique, and many requests are accepted with relatively low upgrade costs. PacifiCorp does not have an expectation that costs are likely to be below the $1 million transmission cost threshold, rather that is a level at which the impacts become significant enough to warrant further consideration of the economics of the resource in question.

To the extent that the transmission upgrades identified to accommodate a TSR increase the transfer capability among the transmission areas modeled in PLEXOS, that transfer capability can be added to the model along with the resource, reducing congestion and increasing the overall benefits of the resource. PacifiCorp's 2025 Integrated Resource Plan (IRP) also includes benefits associated with the interconnection capability associated with transmission upgrades. If 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. 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.

25-035-06 / Rocky Mountain Power
September 17, 2025
DPU Data Request 5.3

DPU Data Request 5.3

> Does the Company intend to enforce the $0.70 surcharge limit of the Communities' low-income plan? If the $0.70 surcharge limit is reached will the program credit adjust accordingly to ensure the low-income plan is fully financed? If not, please elaborate.

Response to DPU Data Request 5.3

> Yes, the Company intends to enforce the $0.70 surcharge limit. However, if modifications to the surcharge limit are ultimately found to be necessary, the Company will file a rate adjustment request, not more than annually. Any and all changes to the rates, fees or tariffs for the program would be filed with the Public Service Commission of Utah (UPSC) for approval, either at the time of the annual report or a separate proceeding.