ROCKY MOUNTAIN
POWER
A DIVISION OF PACIFICORP

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October 5, 2020

VIA ELECTRONIC FILING

Public Service Commission of Utah
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84114

Attention: Gary Widerburg
Commission Administrator

Re: Docket 20-035-04
Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations
Phase I – Revenue Requirement Rebuttal Testimony

Pursuant to the Scheduling Order, Notice of Technical Conference, Notice of Hearings, and Notice of Public Witness Hearing issued by the Public Service Commission of Utah on June 9, 2020 in the above referenced matter, Rocky Mountain Power hereby submits for filing its Phase I – Revenue Requirement rebuttal testimony and exhibits.

Rocky Mountain Power respectfully requests that all formal correspondence and requests for additional information regarding this filing be addressed to the following:

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Sincerely,

Joelle Steward

Vice President, Regulation

cc: Service List Docket No. 20-035-04

CERTIFICATE OF SERVICE

Docket No. 20-035-04

I hereby certify that on October 5, 2020, a true and correct copy of the foregoing was served by electronic mail and/or overnight delivery to the following:

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Rocky Mountain Power
Docket No. 20-035-04
Witness: Joelle R. Steward

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Rebuttal Testimony of Joelle R. Steward

October 2020

Q. Are you the same Joelle R. Steward that submitted direct testimony on behalf of PacifiCorp, d/b/a Rocky Mountain Power ("Rocky Mountain Power" or the "Company") in this proceeding?

A. Yes.

I. PURPOSE OF REBUTTAL TESTIMONY

Q. What is the purpose of your rebuttal testimony?

A. In my rebuttal testimony, I summarize the Company's rebuttal case reflecting certain corrections and updates, respond to various intervenor positions in direct testimony, and provide recommendations to the Public Service Commission of Utah ("Commission") for their consideration in this proceeding. Specifically, I respond to intervenor positions regarding certain capital investments, the Company's renewable energy credits ("REC") balancing account ("RBA"), the Company's rate mitigation proposals, and the Company's Subscriber Solar Program expansion proposal. I also discuss the proposal to delay a portion of the revenue requirement increase to July 1, 2021, for recovery of the Company's investments in its TB Flats II Wind Project, which is part of Energy Vision 2020, and Pryor Mountain Wind Project that have in-service dates affected by the COVID-19 pandemic.

Q. Please provide a summary of the Company's case as updated in its rebuttal filing.

A. In rebuttal, the Company is requesting an overall base rate increase of $72.0 million, which the Company is requesting to be phased in through two rate changes in 2021. Further, the Company continues to propose to offset the base rate increase, in part, for two years by refunding a portion of the deferred tax savings associated with the Tax Cuts and Jobs Act ("TCJA"). Specifically, the Company proposes to pass back approximately $62.7 million of the TCJA deferred tax balance over two years. After consideration of interest, $38.2 million will be returned in 2021 and $26.8 million in 2022. This will result in a 1.1 percent increase in 2021, another 1.1 percent increase in 2022 when the credit is reduced, and a 1.3 percent increase in 2023 when the remaining tax deferral is fully refunded and the credit is eliminated. Further, the Company would align the credit in 2021 with the two-step base rate change such that the credit would be increased in the latter half of the year to fully offset the second base rate increase. However, as I explain later in my testimony, the Company is not opposed to refunding the TCJA deferred tax balance over a longer period of time provided the balance is used to offset the overall proposed base rate increase.

The Company's rebuttal filing continues to reflect the mitigation proposals that reduce the requested revenue requirement increase through (1) the use of the balance in the Sustainable Transportation and Energy Plan ("STEP") regulatory liability account to buy-down the undepreciated plant balances of certain coal-fired generation units, as agreed to in the TCJA proceeding,[1] which reduces the revenue requirement approximately $30.3 million; (2) use of a portion of the TCJA deferred tax benefits to pay off certain regulatory assets; (3) further depreciate the Dave Johnston plant balance, which lowers on-going depreciation expense of $6.1 million; and (4) creation of a regulatory asset to extend the recovery for Jim Bridger Units 1 and 2 to reduce depreciation expense approximately $5.2 million until future STEP funds are accumulated to buy-down the plant balances when the units are retired. Additionally,

[1] *Investigation of Revenue Requirement Impacts of the New Federal Tax Legislation Titled: "An act to provide for reconciliation pursuant to titles II and V of the concurrent resolution of the budget for fiscal year 2018",* Docket No. 17-035-69 (Dec. 21, 2017).

the Company is accepting an OOCS proposal to use the TCJA to offset an additional regulatory asset related to the acquisition of the Craig and Hayden plants. Altogether these combined actions reduce the requested revenue requirement increase by approximately $71.1 million, or 3.6 percent.

Q. Do you have any comments regarding the Company's updated rebuttal case in this proceeding?

A. Yes. This rate case reflects a number of major capital investments made since the Company's last rate case filed in 2014 ("2014 Rate Case"),[2] such as Energy Vision 2020, that allows the Company to continue meeting its core principle of providing energy solutions in the form of safe, reliable, and affordable energy to customers. To this end, the Company is investing approximately $3.6 billion in renewable energy projects and related transmission through calendar year 2021.[3] Notably, the costs associated with this investment are included in the general rate case while the customer benefits of the zero-fuel cost energy and the production tax credits ("PTCs") are proposed to be included in the energy balancing account ("EBA"). Despite the significant investment in this case, the minimal overall net impact to customers is evidence of the Company's commitment to its customers for energy solutions in the form of safe, reliable, and affordable energy.

Q. Please summarize the recommendations you make in your rebuttal testimony.

A. In addition to approving the updated revenue requirement, I recommend that the

[2] *In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations*, Docket No. 13-035-184 Report and Order Approving the Settlement Stipulation dated June 25, 2014. (Aug. 29, 2014).

[3] Direct Testimony of Nikki L. Kobliha at lines 59-60.

Commission allow a partial delay of the January 1, 2021 base rate increase to July 1, 2021 (or 30 days after the last wind project fully goes into service) as a result of the impacts that the COVID-19 pandemic has on the construction of certain large capital investments. I also recommend approval of the Company's rate mitigation proposals as modified in rebuttal testimony.

Q. How is your rebuttal testimony structured?

A. My testimony is structured as follows: Section II provides an overview of the Company's rebuttal position and a summary of the positions in intervenors' testimony; Section III addresses certain capital investments; Section IV addresses the Company's RBA; Section V addresses the Company's rate mitigation proposals; Section VI addresses the Company's Subscriber Solar Program; and Section VII introduces Company witnesses providing supporting testimony in the revenue requirement phase of this proceeding.

II. ROCKY MOUNTAIN POWER'S REBUTTAL POSITION

Q. What is the purpose of this section of your rebuttal testimony?

A. In this section of my testimony, I provide an overview of the direct testimony filed by the intervenors and an overview of the Company's rebuttal position in this proceeding.

Q. Which intervenors filed direct testimony in the revenue requirement phase of this proceeding?

A. Direct testimony in the revenue requirement phase of this proceeding was filed by the following intervenors: Division of Public Utilities ("DPU"), Office of Consumer Services ("OCS"), and Utah Association of Energy Users ("UAE"). I will refer to these parties as the "Filing Parties."

Q. Please provide a comparison of the revenue change proposed by the Filing Parties in their direct testimony.

A. The revenue change proposed by each of the parties' as stated in their testimonies is indicated in Table 1 below.

Table 1: Filing Parties' Revenue Requirement Change

Filing Party	Proposed Revenue Change (in millions)
Company – *as filed*	$95.8
Company – *rebuttal*	$72.0
DPU[4]	$34.1
OCS[5]	($59.3)
UAE[6]	$14.9

The DPU's recommended revenue change does not reflect its recommendation to disallow the Company's investment in Pryor Mountain Wind Project.[7] Further, to calculate its proposed revenue change, UAE used a placeholder return on equity ("ROE") of 9.5 percent in its calculation of proposed revenue requirement change, even though in testimony it deferred to the recommendations of the DPU and OCS.[8] Furthermore, Walmart Inc. did not specify an overall proposed revenue requirement change but filed testimony in the cost of capital phase of this proceeding recommending an ROE of no greater than 9.8 percent, which is the Company's currently authorized ROE.[9]

[4] Direct Testimony of Brenda Salter at line 60.
[5] Direct Testimony of Alyson Anderson at line 55.
[6] Direct Testimony of Kevin C. Higgins at line 173.
[7] Direct Testimony of Joni S. Zenger at lines 21-25.
[8] Direct Testimony of Kevin C. Higgins at lines 950-960.
[9] Direct Testimony of Steve W. Chriss at lines 166-183.

Q. What are the major drivers causing the divergence between the Filing Parties' positions and the Company's direct testimony?

A. The delta between the positions of the Company and the Filing Parties is attributable to several key drivers: the calculation of ROE, capital structure, and a number of proposed adjustments.[10] These adjustments include the regulatory treatment of the prepaid pension and post-retirement welfare asset, prudency of certain capital investments, calculation of property tax, and amortization period of the remaining TCJA balances.

Q. What are the Filing Parties' positions on ROE and the equity portion of capital structure?

A. The Filing Parties' positions on ROE and the equity portion of capital structure are reflected in Table 2 below.

Table 2: Filing Parties' Positions on ROE and Capital Structure

Filing Party	ROE	Capital Structure - Equity
Company – *as filed*	10.2%	53.67%
Company - *rebuttal*	9.8%	53.67%
DPU[11]	9.25%	53.67%
OCS – primary	9.0%	50.00%
OCS – secondary	8.75%	53.67%
Walmart[12]	No greater than 9.8 %	N/A

[10] Company witnesses Mr. Gary W. Hoogeveen, Ms. Ann E. Bulkley and Ms. Nikki L. Kobliha addressed intervenor recommendations regarding ROE and capital structure in their Phase I testimony. Company witnesses submitting revenue requirement rebuttal testimony address the various adjustments proposed by the Filing Parties.
[11] Direct Testimony of Casey J. Coleman at lines 76-86.
[12] Direct Testimony of Steve W. Chriss at lines 166-183.

Company witnesses Mr. Gary W. Hoogeveen, Ms. Ann E. Bulkley, and Ms. Nikki L. Kobliha address the Filing Parties' positions regarding ROE and capital structure in rebuttal testimony filed during the cost of capital phase of this proceeding.

Q. UAE witness Mr. Kevin C. Higgins states that UAE is not specifically recommending an ROE and is deferring to the recommendations of DPU and OCS but to calculate UAE's revenue requirement uses an ROE of 9.5 percent based on the Company's recent stipulation to in its Washington general rate case.[13] How do you respond?

A. Mr. Higgins is referring to the rate case filed in Washington by PacifiCorp d/b/a Pacific Power ("Pacific Power") on December 13, 2020, Docket UE-191024.[14] On July 20, 2020, a stipulation was entered into by the parties of that proceeding resolving all disputed issues, including ROE. As part of that negotiated stipulation, the parties agreed to maintain Pacific Power's currently authorized return on equity of 9.5 percent that was approved in Pacific Power's last Washington rate case filed in 2015, Docket UE-152253.[15]

Mr. Higgins claims that by using this placeholder in this proceeding in order to provide "a more realistic depiction of UAE's proposed revenue requirement," he does not intend to supplant the Commission's consideration of traditional cost of capital analysis offered by other parties in this proceeding. However, instead of using the ROE proposed by either DPU or OCS, which I assume would not provide a "realistic depiction of UAE's proposed revenue requirement," Mr. Higgins reaches to the recent

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[13] Direct Testimony of Kevin C. Higgins at lines 957-960.
[14] *WUTC v. PacifiCorp d/b/a Pacific Power & Light Company*, Docket Nos. UE-191024, UE-190750, UE-190929, UE-190981, UE-180778 (cons.).
[15] Docket Nos. UE-191024, Settlement Stipulation at 5 (filed July 20, 2020).

stipulation entered into by Pacific Power in its Washington general rate case. The Commission should reject any implication that an ROE from a stipulation in another jurisdiction is appropriate to set ROE in this proceeding. While I did not participate in the settlement of Pacific Power's Washington rate case, it was the result of a compromise among the parties in that case. As explained in the stipulation, "[t]he parties have entered into the Stipulation to avoid further expense, inconvenience, uncertainty, and delay of continuing litigation. The Parties recognize that the Stipulation represents a compromise of the Parties' position."[16] Thus, the 9.5 percent accepted by Pacific Power is part of a negotiated stipulation resolving issues in its general rate case does not set precedent.

Please see the cost of capital rebuttal testimony of Mr. Hoogeveen and Ms. Bulkley that support the Company's requested 9.8 percent ROE.

Q. Please summarize generally the Company's positions on rebuttal.

A. The Company's rebuttal filing reflects a revised revenue requirement and revenue increase of $72.0 million attributable to certain adjustments in rebuttal testimony, which can be classified as either: (1) corrections; or (2) updates due to more recent information or in response to the Filing Parties' recommendations. These adjustments are set forth in Table 3 below.

[16] Id. at 18.

Table 3: Company's Requested Increase in Rebuttal (in millions)

Direct Filing Request	$ 95.8
Reduce ROE from 10.20% to 9.80%	$ (22.3)
Company Correction	$ (4.0)
Updates/Intervenor Adjustments	$ 10.8
Changes to Capital Projects	$ (28.5)
Rate Mitigation Proposal Revisions	$ (2.2)
January 1, 2021 Rate Change	$ 49.5
July 1, 2021 Rate Change	$ 22.5
Total Rate Change	$ 72.0
Schedule 197 Sur-Credit	$ 62.7

In the development of a rate case and through the process of discovery and intervenor testimony, it is not uncommon that corrections are identified in the direct filing. In this instance, the corrections are not substantial and constitute a small decrease.

The updates are due to more recent information and changes in position in response to the intervenor testimony. For instance, the Company revised net power costs to align with the updated wind in-service dates discussed by Mr. Timothy J. Hemstreet and Mr. Robert Van Engelenhoven, which results in a net increase of $3.4 million. This is explained in the rebuttal testimony of Mr. David G. Webb. Lastly, the updates reflect the Company's acceptance of certain intervenor adjustments, which are explained by Mr. Steven R. McDougal.

III. CAPITAL INVESTMENTS

Q. What is the purpose of this section of your rebuttal testimony?

A. In this section of my rebuttal testimony, I discuss the Company's proposal to delay a portion of the rate increase due to a projected delay for the in-service dates on portions of the TB Flats II and Pryor Mountain Wind Projects attributed to the COVID-19 pandemic. I address UAE witness Mr. Higgins' proposal for the Company to recover its investment of the Pryor Mountain Wind Project through the EBA instead of base rates. Finally, I address OCS witness Mr. Philip Hayet's recommendation that from a policy perspective, the Commission should deny the Company's recovery of the Foote Creek I repowering Project and the Pryor Mountain Wind Project because the Company did not file requests for resource decisions under U.C.A §54-17-402.

Q. Has the Company provided updates on the construction status of the Energy Vision 2020 new wind projects and the Pryor Mountain Wind Project in rebuttal testimony?

A. Yes. As explained further in the rebuttal testimony of Messrs. Hemstreet and Van Engelenhoven, because of construction delays due to the impacts of the COVID-19 pandemic, portions of the TB Flats II Wind Project and the Pryor Mountain Wind Project are estimated to be placed into service in 2021, after the January 1, 2021 rate effective date in this case.

Q. Because of these delays, is the Company proposing an alternative rate recovery methodology for the capital costs associated with the TB Flats II and Pryor Mountain Wind Projects in this proceeding?

A. Yes. The Company is proposing to delay the rate change associated with the revenue requirement for the portions of the TB Flats II and Pryor Mountain Wind Projects now projected to be in-service in 2021. Specifically, the Company is requesting a rate change effective July 1, 2021, or 30 days after the final in-service date for the projects if there are further delays beyond the Company's control. In the cost of service and pricing phase, Mr. Robert M. Meredith will include the proposed rates for July 1, 2021 as well as January 1, 2021 in his rebuttal testimony and exhibits. Before the second rate change goes into effect, the Company will file a notice with the Commission to confirm the projects are in-service. The Company's rebuttal case also reflects the revised in-service dates for the benefits associated with these resources, zero-fuel costs and PTCs, in the base EBA rates.

Q. Why is the delayed rate change you propose for these resources reasonable?

A. The two-step rate change to recover the forecast costs of these resources is reasonable in this circumstance because the delays in the projects have been attributed to the COVID-19 pandemic, which is clearly outside the Company's control. The Company's proposal is appropriate for a number of reasons.

First, while I am not an attorney, my understanding is that U.C.A. §54-4.4.1(1) grants the Commission authority to adopt "any method of rate regulation" which is consistent with the Utah Public Utilities Act and is in the public interest and results in just and reasonable rates. U.C.A. §54-4.4.1(2) provides that rate regulation includes "other components, methods, or mechanisms approved by the Commission." Thus, it is within the Commission's authority to approve a two-step rate change as the Company proposes in rebuttal. The Commission's flexibility in establishing rates is further demonstrated in U.C.A. §54-7-13.4, which allows a utility to file for alternative cost recovery of a major plant if a final Commission order in such utility's general rate case proceeding is within 18 months of the projected in-service date of the addition. The Company received approval for alternative cost recovery of major capital additions under U.C.A. §54-7-13.4 in Docket Nos. 10-035-13 and 10-035-89.[17] The Company did not file for recovery under U.C.A. §54-7-13.4 because it is in a general rate case before the Commission. Furthermore, the Commission has approved similar multi-step rate recovery proposals in the past. For example, in the Company's last two rate cases, the Commission approved stipulations that provided for multi-year rate increases.[18]

Second, the circumstances leading to the Company's two-step rate increase are beyond the Company's control. As explained further by Messrs. Hemstreet and Van Engelenhoven, the Company has received notification from its vendors that the supply chain has been impacted by the COVID-19 pandemic. The Company has diligently worked to mitigate any impacts on cost and construction by working with vendors and contractors in order to preserve project benefits and minimize costs. Even though a portion of these projects are placed into service in 2021, they continue to be eligible for 100 percent of the PTCs.

Furthermore, under the Company's proposal, the costs and benefits of these wind projects are better matched as the benefits of zero-fuel cost energy and PTCs of the resources will flow through to customers in the EBA once the projects are incorporated into rates. If the Company's proposed two-step rate change is not

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[17] *In the Matter of the Application of Rocky Mountain Power for Alternative Cost Recovery for Major Plant Additions of the Ben Lomond to Terminal Transmission Line and Dave Johnston Generation Unit 3 Emission Control Measure, In the Matter of the Application of the Utah Association of Energy Users for a Deferred Accounting Order Directing Rocky Mountain Power to Defer Incremental REC Revenue for Later Ratemaking Treatment, In the Matter of the Application of Rocky Mountain Power for Alternative Cost Recovery for Major Plant Additions - Populus to Ben Lomond Transmission Line and the Dunlap I Wind Project,* Docket Nos. 10-035-13, 10-035-14, and 10-035-89 (cons.), Order Approving Settlement Stipulation (Dec. 21, 2010).

[18] *In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations*, Docket No. 13-035-184 Report and Order Approving the Settlement Stipulation dated June 25, 2014. (Aug. 29, 2014); *In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations,* Docket Nos. 11-035-200, 12-025-79, and 12-035-80 (cons.), Report and Order (Sept. 19, 2012).

accepted, the Company should be able to make adjustments to the EBA and to retain the portion of the benefits associated with the capital not in rates. Mr. McDougal's rebuttal testimony provides additional details regarding the two-step rate increase.

Q. UAE witness Mr. Higgins recommends treating the Pryor Mountain Wind Project as the equivalent of a qualifying facility ("QF") with recovery at $26.00 per megawatt-hour ("MWh") for 20 years.[19] Does the Company agree with this treatment or his calculation?

A. No. Mr. Higgins' proposed treatment is essentially a creative disallowance of costs for a prudently-incurred generation resource. Mr. Higgins does not contest that the wind project will provide customers net benefits over the life of the project but nonetheless recommends a misguided cost recovery scheme that penalizes the Company. In his rebuttal testimony, Mr. Rick T. Link explains why the comparison to a QF is inappropriate and that the project should not be treated as a power purchase agreement. Additionally, Mr. Link explains why the terminal value used in the Company's analysis is appropriate, and why Mr. Higgins' criticism was incorrect.

Q. OCS witness Mr. Hayet asserts that from a policy perspective the Commission should not approve the Foote Creek I and Pryor Mountain projects for recovery because of the Company's departure from regulatory practices.[20] How do you respond?

A. As I understand Mr. Hayet's testimony, he recommends that from a policy perspective, the Commission should reject the Company's request for recovery of its investments in Foote Creek I and Pryor Mountain because it did not request pre-approval under

[19] Direct Testimony of Kevin C. Higgins at lines 880-884.
[20] Direct Testimony of Philip Hayet at lines 662-687.

U.C.A §54-17-402, which allows voluntary requests for resource decisions. Mr. Hayet would have the Commission ignore evidence in this proceeding supporting the recovery on and of these investments because the Company opted not to request pre-approval, which it was not required to do. Such a Commission decision denying prudently incurred investments would deter a utility taking advantage of time-limited investments that would deliver customer benefits if it was subject to the risk of the projects being rejected for recovery in a rate case because it did not make a *voluntary* request for pre-approval.

Setting this aside, Mr. Hayet implicitly imposes a requirement in U.C.A §54-17-402 that does not exist in that if a utility does not avail itself to that section with respect to an investment, such investment such be denied recovery in the next filed rate case. While I am not an attorney, my understanding is that U.C.A §54-17-402 is voluntary. Specifically, U.C.A §54-17-402 provides that "… before implementing a resource decision, and energy utility *may* request that the commission approve all or part of a resource decision …." (emphasis added) If the legislature wanted to require a utility to submit resources decisions for pre-approval, the statutory language would not reflect conditional language such as "may request" and instead would read "shall request."

The Commission recognized this in its decision in the Company's voluntary request for approval of resource decision to repower certain wind facilities filed on June 23, 2017.[21] In its decision in that proceeding, the Commission approved the repowering of 11 of the 12 Company-owned wind facilities. It did not pre-approve the

[21] *Voluntary Request of Rocky Mountain Power for Approval of Resource Decision to Repower Wind Facilities*, Docket No. 17-035-39.

Company's investment in Leaning Juniper project.[22] With respect to that project, the Commission stated:

> We decline to approve the voluntary request for resource decision for the Leaning Juniper project. *This decision does not mean PacifiCorp may not still pursue that project.* It means that the Leaning Juniper repowering project will not have the protections afforded by Utah Code Title 54, Chapter 17, Part 4. *If PacifiCorp chooses to implement the project, the project will be subject to a standard prudence review in future general rate cases.* Our order declining to approve the project in this docket may not be interpreted to pre-judge that issue in any way.[23]

In not approving the Company's request regarding Leaning Juniper, the Commission acknowledged that the Company could still pursue the project and, if implemented, the project would be subject to the standard prudence review in a future general rate case. Thus, whether a project is not part of a voluntary request or is part of a voluntary request and denied, ultimately the project if implemented, is subject to the standard prudence review of a utility's future rate case.

Q. Mr. Hayet claims that the Company could have sought pre-approval of the Foote Creek I and Pryor Mountain Projects on an expedited basis based on its experience in Docket No. 08-035-35.[24] How do you respond?

A. I disagree with Mr. Hayet. U.C.A §54-17-402(7) provides that unless the Commission determines additional time is required, a Commission decision should be issued within 180 days of a utility request for resource decision. However, there is no guarantee that a Commission decision will be issued in 180 days as provided in the statute or that a request to treat a matter in an expedited manner can always be granted. Thus, the

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[22] Docket No. 17-035-39, Report and Order at 20 (May 25, 2018).
[23] *Id.* (emphasis added)
[24] Direct Testimony of Philip Hayet at lines 562-571.

Company has to weigh voluntarily requesting a resource decision from the Commission against a time-sensitive nature of a particular project.

Q. Do you agree with Mr. Hayet that under his proposal the Company can gain rate treatment of the Foote Creek I and Pryor Mountain projects once it proves the need for additional resources as part of its Integrated Resource Plan ("IRP") and bid them into the next wind resource solicitation or the current 2020 All Source 2020 Request for Proposal ("2020AS RFP")?

A. No. As discussed by Mr. Link, the recent IRPs demonstrate that the Company has a near-term and long-term resource need and these wind projects contribute to meeting those capacity shortfalls. The analysis to support the projects was properly done at the time the resource decisions were made, which was based on timing that would allow the Company to maximize PTC qualification known at that time. A new evaluation of the resources as part of a future IRP or as part of the current 2020AS RFP is unnecessary. Moreover, the 2020AS RFP, as approved by the Commission in Docket No. 20-035-05,[25] does not include provisions for incorporating Company-owned benchmark resource bids.

IV. RBA

Q. What is the purpose of this section of your rebuttal testimony?

A. In this section of my testimony, I address OCS witness Ms. Donna Ramas' recommendation to change the approach on how REC revenues are recognized in rates.

Q. How are REC revenues currently reflected in rates?

A. Currently, the difference between actual REC revenues and the REC revenues set in

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[25] *Application of Rocky Mountain Power for Approval of Solicitation Process for 2020 All Source Request for Proposals,* Docket No. 20-035-35, Order Approving 2020 All Source RFP (July 17, 2020).

rates are reconciled in the REC Balancing Account, Schedule 98, where revenues are trued up on an annual basis through a surcharge or surcredit. Annual filings are made with the Commission to true-up revenues and reset the surcharge or surcredit.

Q. What is Ms. Ramas' recommendation?

A. Instead of the current annual reconciliation to true up of REC revenues, Ms. Ramas recommends that a deferral approach be used.[26] Specifically, she proposes that once the final true up for calendar year 2020 is completed, Schedule 98 be discontinued. Beginning January 1, 2021, the Company would account for the difference between actual REC revenues and REC revenues incorporated in rates by deferring the difference to a regulatory asset/regulatory liability. Ms. Ramas proposes that the resulting balance in the deferral account be addressed in a future rate case proceeding. Also, Ms. Ramas does not oppose the Company continuing to retain 10 percent of the REC revenues as an incentive to market and obtain additional value for the available RECs.

Q. Does the Company agree with Ms. Ramas' proposed deferral approach for REC revenues?

A. Yes, in part. The Company is not opposed to the deferral approach in lieu of the annual rate adjustment that is currently done through Electric Service Schedule No. 98, but would recommend it be allowed to retain the ability to propose ratemaking treatment for any regulatory asset or liability balance outside of a general rate case. For example, the Company could propose outside of a general rate case to apply the regulatory liability balance against another cost that would otherwise increase rates or to initiate a

[26] Direct Testimony of Donna Ramas at lines 269-347.

credit to customer rates to offset some other cost, such as an EBA charge. Any application of the balance would be subject to review by parties and approval by the Commission. In his testimony, Mr. McDougal provides an example of a Company deferral account that works similar to Ms. Ramas' proposal.

V. RATE MITIGATION PROPOSALS

Q. What is the purpose of this section of your rebuttal testimony?

A. In this section of my testimony, I explain the small modification that the Company is proposing to its rate mitigation proposals. I also address proposals made by OCS witness Ms. Ramas to use the TCJA deferred tax balance to mitigate rates set in this proceeding.

Q. Please explain the modification that the Company is proposing to its rate mitigation proposals.

A. The Company is proposing to slightly modify one of the rate mitigation proposals that it set forth in direct testimony. Specifically, the Company proposes to align the TCJA tax benefit balance to be credited to customers in 2021 with the two-step base rate change. The Company's modification to its proposed credit to customers in 2021 would fully offset the second base rate increase in 2021. The Company's modification is appropriate as it will ensure that customers will not experience rate volatility when the second base rate increase becomes effective in 2021. The Company's calculation for this change will be shown in the rebuttal testimony of Mr. Robert M. Meredith in the cost of service and pricing phase of this proceeding.

Q. Are there any other modifications to the Company's rate mitigation proposals?

A. Yes. In order to narrow the issues in this proceeding, the Company does not oppose

Ms. Ramas' recommendation that a portion of the TCJA deferred tax balance be applied to buying down Utah's share of the unamortized balances in Federal Energy Regulatory Commission ("FERC") account 114, Electric Plant Acquisition Adjustment, and FERC account 115, Accumulated Provision for Asset Acquisition Adjustment, associated with the plant acquisitions of the Craig and Hayden plants.[27] In his testimony, Mr. McDougal incorporates this proposal into the revenue requirement.

Q. Does Ms. Ramas make any further recommendations regarding the use of the TCJA tax deferred balance?

A. Yes. She makes a recommendation regarding the TCJA deferred tax balance remaining after the buy down of the undepreciated plant balances for the Dave Johnston generating plant and pay down of certain regulatory assets, which is approximately $62.7 million in this rebuttal filing. Instead of returning the remaining balance to customers over two years as the Company proposes, Ms. Ramas recommends that the remaining balance be returned to customers over ten years.[28]

Q. How do you respond?

A. While the Company does not agree that a revenue decrease as recommended by OCS is justified or warranted in this proceeding, the Company does not generally oppose a longer amortization period to return the remaining TCJA deferred tax balance to customers. The Company continues to believe that the amortization period ultimately decided on by the Commission should be set to offset the rate impact from this proceeding in order to phase in an increase in the revenue requirement.

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[27] Direct Testimony of Donna Ramas at lines 1529-1570.
[28] Direct Testimony of Donna Ramas at lines 82-83.

VI. SUBSCRIBER SOLAR

Q. What are the parties' positions in response to the Company's proposal for a new Subscriber Solar program structure that would provide for expansion?

A. The DPU, through its witness Mr. Robert A. Davis, generally supports the revised program structure but has concerns about certain details.[29] The OCS, through its witness Ms. Alyson Anderson, opposes the Company's proposed expansion of the Subscriber Solar program because, she argues, the program is lacking details and should be addressed outside of the rate case.[30] Ms. Sarah Wright on behalf of UCE, supports the expansion of the program but proposes that future expansions of the program accommodate participation for low-income customers.[31] All parties raise concerns about the risks of shifting costs to other customers.

Q. What is the Company's general response to the issues raised by parties?

A. First, I think it's worth noting that all three parties generally recognize that providing the program as another option for customers has been worthwhile. As the Company explained in direct testimony, the Subscriber Solar program has been extremely popular and has been fully subscribed since shortly after it launched in 2015.[32] As such, the Company has been eager to expand the program in response to the continued customer interest. However, because the initial program structure did not readily enable expansion and relied on an alternative rate structure from customers' normal service schedules, the Company decided to more comprehensively consider revisions to the program in the general rate case to better align the program structure with changes in

[29] Direct Testimony of Robert A. Davis at lines 88-91.
[30] Direct Testimony of Alyson Anderson at lines 188-212.
[31] Direct Testimony of Sarah Wright at lines 140-149.
[32] Direct Testimony of William J. Comeau at lines 76-77.

rate design proposed therein. Additionally, the Company believed that consideration of the revised program structure in the general rate case would facilitate a more timely process after the rate case to obtain approval of the specific program rates once a new resource has been acquired. Mr. Kyle T. Moore is submitting rebuttal testimony on behalf of the Company to further respond to concerns raised by the parties.

Q. Ms. Anderson characterizes the Company's request in this proceeding as seeking pre-approval of an expanded project.[33] Is this correct?

A. No. The Company is seeking approval for the new program structure and the opportunity to expand it with new resources. The Company is not seeking pre-approval of any new resources. The tariff changes in this proceeding do not include rates for the expanded program. If the Company receives approval of the structure, the Company would then seek to acquire a competitive resource for the program, calculate the rates and file the tariff changes for review by stakeholders and approval from the Commission. Similarly the Company would need to file tariff changes for any future expansion of the program for new resources. Approval of the new program structure in this proceeding does not pre-approve the program expansion; it provides the Company the opportunity to seek expansion for new participants with new resources after the rate case. By having some certainty on the program structure from the rate case, the Company would have more certainty to be able to develop the program marketing materials and procure the new resource for the expanded program more quickly after the rate case and before expiration of tax credits.

[33] Direct Testimony of Alyson Anderson at lines 133-143.

VII. INTRODUCTION OF REBUTTAL WITNESSES

Q. Please identify the witnesses submitting rebuttal testimony in the revenue requirement phase of this proceeding and the subject of their testimony.

A. In addition to myself, the Company witnesses filing rebuttal testimony and the subjects of their testimony are as follows:

Nikki L. Kobliha, Vice President, Chief Financial Officer and Treasurer, responds to intervenor testimony regarding pension settlement losses and the net prepaid pension and other postretirement asset.

Rick T. Link, Vice President of Resource Planning and Acquisition, addresses intervenor testimony regarding the Company's economic analysis and pricing proposal for the Pryor Mountain wind project along with the economic analysis for repowering Foote Creek I.

Robert Van Engelenhoven, Resource Development Director, provides an update of the construction status of, and responds to intervenor testimony regarding, the Pryor Mountain Wind Project.

Timothy J. Hemstreet, Managing Director of Renewable Energy Development, provides an update of the costs and construction status of the Energy Vision 2020 new wind projects. He also provides a construction update regarding the Dunlap and Foote Creek I repowering projects and an update on the expenditures of all of the Company's repowering projects. Mr. Hemstreet also responds to the intervenor testimony regarding the Foote Creek I repowering project.

Dana M. Ralston, Senior Vice President of Thermal Generation and Mining, addresses intervenor testimony regarding the outages at Lake Side 2 Unit 3 and Blundell Unit 2.

Curtis B. Mansfield, Vice President of Transmission and Distribution Operations, provides an update to the Company's Wildland Fire mitigation plan and responds to intervenor testimony regarding the Company's Advanced Metering Infrastructure project in Utah.

David G. Webb, Manager of Net Power Costs, provides the rebuttal net power costs that include the change for the wind in-service dates. He also responds to intervenor testimony regarding proposed net power costs adjustments.

Steven R. McDougal, Director of Revenue Requirements, presents modifications to the revenue requirement due to accepting certain Intervenor adjustments, corrections identified since the direct filing and updates based on current information. He also responds to various adjustments made by intervenors in direct testimony including adjustments to revenues, operations and maintenance expense, tax, and rate base.

Kyle T. Moore, Power Market Originator, responds to the intervenor testimony regarding the Company's proposed expansion of the Subscriber Solar program.

Julie Lewis, Vice President of People, responds to intervenor testimony recommending adjustments to the Company's wage and labor expenses.

VIII. RECOMMENDATION

Q. Please summarize the Company's recommendation.

A. The Commission should approve the updated revenue requirement that I describe above and that is supported by the other Company witnesses' rebuttal testimonies. I also recommend that the Commission allow a partial delay of the January 1, 2021 base rate increase to July 1, 2021 (or 30 days after the last wind project fully goes into service) as a result of the impacts that the COVID-19 pandemic has on the construction of certain large capital investments and approve the Company's rate mitigation proposals as modified in rebuttal testimony.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Rocky Mountain Power
Docket No. 20-035-04
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Rebuttal Testimony of Nikki L. Kobliha

October 2020

Q. Are you the same Nikki L. Kobliha who previously submitted direct testimony and rebuttal testimony in the cost of capital phase in this proceeding on behalf of PacifiCorp d/b/a Rocky Mountain Power ("PacifiCorp" or the "Company")?

A. Yes, I am.

I. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your rebuttal testimony with respect to pension and other postretirement costs?

A. In my rebuttal testimony in this phase, I respond to the testimony of Utah Association of Energy Users ("UAE") witness Mr. Kevin Higgins and the Office of Consumer Services ("OCS") witness Ms. Donna Ramas in matters related to pension settlement losses and the net prepaid pension and other postretirement asset (also referred to in my testimony as the "net prepaid").

Q. Please summarize your rebuttal testimony.

A. My rebuttal testimony (a) explains why it is appropriate for the Company to be allowed an opportunity to recover pension settlement losses, and I provide an alternative recovery treatment for the Commission's consideration and (b) provides additional information regarding the Company's request to include its net prepaid pension and other postretirement asset in rate base.

Specifically, my rebuttal testimony responds to (a) the recommendations by both Ms. Ramas and Mr. Higgins to reject the Company's inclusion of its projected pension settlement loss in the test period and to instead allow deferral and amortization over time and (b) the recommendations by both Ms. Ramas and Mr. Higgins to exclude the net prepaid from rate base.

Pension Settlement Losses

Q. Mr. Higgins suggests that inclusion of a projected pension settlement loss in the test period is "too speculative" and does not reasonably represent ongoing pension cost to the Company while acknowledging that settlement losses are likely to be more common in a low interest rate environment.[1] How do you respond to these views?

A. While it is difficult to accurately project future pension settlement losses, the Company based its projection on the best available information from its actuaries to determine there would be an estimated pension settlement loss in the test period. The Commission previously denied the Company's request to defer the impacts of pension settlement events in its order in Docket No. 18-035-48, stating that the loss was not unforeseeable or extraordinary and therefore not eligible for deferral between general rate proceedings. Based on this view, the Company believes it is appropriate to use the best available information to project pension settlement losses in the test period.

Q. Both Mr. Higgins and Ms. Ramas recommend that starting with the test year in this proceeding, settlement losses (or gains) triggered by the excess of annual lump sum distributions over the applicable threshold be deferred and amortized over approximately 20 years.[2] How do you respond to this recommendation?

A. In order to recover these costs, which have not been challenged as imprudent, the Company recommends some level of pension settlement losses be established in base rates. The Company's primary recommendation is that base rates reflect pension

[1] Direct Testimony of Mr. Kevin C. Higgins at lines 730-735.
[2] Direct Testimony of Ms. Donna Ramas at lines 507-515. Direct Testimony of Mr. Kevin Higgins at lines 737-742.

settlement losses using the information reflected in the test period. Alternatively, the Company recommends establishing a balancing account with an initial amount reflected in base rates using the pension settlement loss reflected in the test period. If neither of these options are acceptable, the Company's final option would be as it proposed in Docket No. 18-035-48, which requested the ability to defer and amortize all actual settlement losses going forward.

Absent one of these alternatives, the Company would not have the opportunity to recover pension settlement losses, which are merely amounts that would have otherwise been subject to recovery as part of net periodic benefit cost absent the pension settlement accounting trigger. Both Ms. Ramas and Mr. Higgins acknowledge this, with Mr. Higgins specifically stating that he does not "challenge the recovery" of the forecast settlement loss.[3]

Q. Please describe the Company's alternative recommendation for a pension and other post-retirement balancing account.

A. As an alternative to its initial filing, the Company proposes to establish a balancing account to track both on-going net periodic benefit cost of its pension and other post-retirement plans, pension settlement losses and any other potential settlement or curtailment gains or losses in the plans. A balancing account would alleviate parties' concerns over what is "in rates" as described below and the difficulty in projecting costs accurately. The Company currently has a property insurance balancing account that works similarly in that revenue requirement is established in each general rate case based on the expected level of expense with the intent to true up to any differences

[3] Id.

between actual and expected expense between general rate cases. If a balancing account is approved, the Company recommends including the regulatory asset or liability balance in the net prepaid pension and other postretirement asset for rate base purposes, as discussed below.

Net Prepaid Pension and Other Postretirement Asset

Q. Both Ms. Ramas and Mr. Higgins recommend excluding the net prepaid pension and other postretirement assets from rate base suggesting that the Company has not truly borne the costs to finance the net prepaid based on a comparison of the amount of net periodic benefit cost deemed to be "in rates" relative to actual net periodic benefit costs. Do you agree with this basis for recommending the net prepaid be excluded from rate base?

A. No, I do not. I disagree with Ms. Ramas' statements and Mr. Higgins' inference that the Company has not borne the costs to finance the net prepaid because actual net periodic benefit costs are less than the amount included in the test period in the last general rate case and that the net prepaid should be computed using the amount that is reflected "in rates."

In a general rate case proceeding, the Commission sets rates to recover an overall revenue requirement comprised of a reasonable calculation of the costs and investments expected to be incurred for the period when the rates will be in effect. During the rate effective period, costs will vary from the amounts estimated in determining rates. Thus, the basis for establishing recovery of the net periodic benefit cost associated with the Company's pension and other postretirement plans is no different than that for other operating costs. To isolate net periodic benefit cost for the

Company's pension and other postretirement plans is unprincipled and disregards variances in other actual costs compared to what was estimated in setting rates.

Q. Do Mr. Higgins and Ms. Ramas make valid arguments to support using the amounts viewed as "in rates" in their analyses?

A. No they do not. While both Mr. Higgins and Ms. Ramas attempt to rely on the amount "in rates" as being that which was included in the Company's test period in its last general rate case, they each acknowledge that this is not how rates are determined and seem to agree with the Company's view on this point.

Mr. Higgins' states that "Utah customers fully fund these [pension] costs," noting the costs are not reset every year and thus are not reimbursed dollar for dollar since "that is not how ratemaking is done."[4] Ms. Ramas also acknowledges that rates are not reset annually; actual amounts will vary from year to year and both historical and forecast test periods have been used with no balancing account or true up.[5]

Ms. Ramas' analysis is centered on her view that in order for the Company to demonstrate it has borne the costs to finance the net prepaid, at a minimum, the actuarially determined expense would have to equal the amount collected "in rates" each year.[6] Ms. Ramas compared actual expense to this amount for each year since the last general rate case, suggesting the Company did not bear any financing costs but indicates this is based on a "hypothetical assumption" of what is in base rates.[7] She also acknowledges that "the amount ultimately included in the approved revenue

[4] Direct testimony of Mr. Kevin C. Higgins at lines 381-384, including footnote 15.
[5] Direct testimony of Ms. Donna Ramas at lines 1277-1290.
[6] Direct testimony of Ms. Donna Ramas at lines 1269-1272.
[7] Direct testimony of Ms. Donna Ramas at lines 1307-1310.

requirement in the case is not known"[8] due to the last case being settled and thus her analysis is included for "illustrative purposes."[9] Mr. Higgins also acknowledges that the last general rate case was settled and references the test period expense in that case as a *representation* of the amount "in rates."[10]

As described above, the Company alternatively recommends a balancing account be established for net periodic pension and other postretirement costs, which I believe would alleviate Ms. Ramas' and Mr. Higgins' concerns regarding what amounts are in rates and who bears the cost to finance the net prepaid.

Q. Ms. Ramas and Mr. Higgins both mention that the Company's pension and other postretirement plans were in a net accrued position in certain historical years yet it was not included as an offset to rate base. Ms. Ramas suggests it would be unfair to charge ratepayers a return on the net prepaid today since the net accrued liability was not included in rate base historically.[11] How do you respond?

A. While I agree that the Company was in a net accrued pension and other postretirement position in historical periods at which time the net accrued was not presented as an offset to rate base, the Company is proposing only prospective financing costs be included in rates. More importantly, there have been many years in which the Company has been in a net prepaid asset position yet the net prepaid was not included in rate base.

As indicated by Mr. Higgins and Ms. Ramas, the Company was in a net accrued position from as early as 1998 through 2006; however, since that time, the Company

[8] *Id.*
[9] Direct testimony of Ms. Donna Ramas at lines 1311-1314.
[10] Direct testimony of Mr. Kevin C. Higgins at lines 346-348.
[11] Direct testimony of Ms. Donna Ramas at lines 1255-1259.

has been in a net prepaid position. The net prepaid averaged approximately $200 million from 2014 at the time of the Company's last general rate case filing through 2019, compared to an average net prepaid of nearly $8 million from 1998 through 2013. Please refer to Exhibit RMP___(NLK-1RR) in which I estimate the magnitude of the cumulative impact to revenue requirement if the net prepaid had been included in rate base in the periods for which information is available.

Exhibit RMP___(NLK-1RR) extends from Company witness Mr. Douglas K. Stuver's analysis in Exhibit RMP___(DKS-1R) in the Company's last general rate case in Docket No. 13-035-184[12]. In that exhibit, Mr. Stuver estimated the impact to revenue requirement that would have occurred had the net prepaid been included in rate base for the periods presented therein. For purposes of my illustration, I summarize the revenue requirement impact for the years presented in Exhibit RMP___(DKS-1R) from 1993 (the earliest year information was available for the other postretirement plan) through 2013 (the final year for which actual balances were available at the time). As one can see in Exhibit RMP__(NLK-1RR), the cumulative impact to revenue requirement through 2013 would have been a benefit to customers of nearly $2 million. By extending the analysis through 2019, the cumulative impact to revenue requirement over the full time period would have been an increase of nearly $50 million. While certain simplifying assumptions were made in the compilation of these estimates, such as not accounting for the time value of money and changes in the Utah allocation factor, rate of return and use of total company balances, my analysis clearly demonstrates that

[12] *In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations*, Docket No. 13-035-184, Rebuttal Testimony of Douglas K. Stuver (June 4, 2014).

customers have not been harmed by the net prepaid (accrued) pension and other postretirement balance having been excluded from rate base and that, in fact, the Company lost the opportunity to recover significant costs to finance the net prepaid to date.

Q. As further rational for Mr. Higgins' recommendation to exclude the net prepaid from rate base, he suggests to do so would result in an unreasonable transfer of risks to customers and indicates the issue is a matter of timing difference that should be borne by the Company.[13] How do you respond?

A. Mr. Higgins' statements regarding the timing difference between contributions and net periodic benefit cost being a business risk the Company must manage is misplaced. The timing difference in the case of the net prepaid pension and other postretirement asset is driven by accounting requirements for expense recognition relative to funding requirements and occurs over the very long-term lives of the plans. Funding the pension plan is not unlike the Company's investments in property, plant and equipment that are utilized and depreciated over what are often very long useful lives. In this example, the Company finances the investments in the property, plant and equipment, recovers costs from customers based on annual depreciation expense over the useful lives and is allowed a return on its investment by including the net balance in rate base.

[13] Direct testimony of Mr. Kevin C. Higgins at line 363 and lines 385-387.

Q. Ms. Ramas states that allowing the net prepaid to be included in rate base "could incentivize" the Company to contribute excess cash to the plans in order to earn its authorized return on those excess contributions and suggests that this would require scrutiny to ensure the plans are being funded prudently.[14] What is your response?

A. I disagree with Ms. Ramas' suggestion that the Company would be incentivized to make excess contributions to its plans in order to earn an incremental return on the net prepaid. While there is flexibility in the level of contributions that can be made to the plans, contributions are subject to certain income tax deductibility limitations. Additionally, upon plan termination, any excess plan assets in the pension and other postretirement plans would be subject to significant excise and ordinary income taxes unless utilized for another qualifying plan. It is in the best interest of both customers and the Company to properly manage its plans to minimize exposure to such taxes and to avoid making contributions in excess of deductibility limits. It is also important to remember that contributions increase plan assets leading to higher expected asset returns which reduce pension cost.

Q. Mr. Higgins recommends reducing the allowed return on the net prepaid pension and other postretirement assets to the expected return on assets assumption applicable to each plan.[15] Do you agree with this recommendation?

A. No I do not. Mr. Higgins' recommendation would result in the Company not being made whole for its costs to finance the contributions in excess of expense that have given rise to the net prepaid. The Company does not specifically obtain financing for

[14] Direct testimony of Ms. Donna Ramas at lines 1367-1372 and lines 1373-1375.
[15] Direct testimony of Mr. Kevin C. Higgins at lines 410-413.

its pension and other postretirement plan contributions such that they are financed with the blend of long-term debt and equity described in the cost of capital portion of my testimony. Thus, the expected return on assets assumption is irrelevant when considering the Company's cost to finance the contributions. The net prepaid is no different than any other rate base item in that it represents the difference in timing of cash outlays and the recognition of the related expense. Like any other rate base item, this timing difference results in the Company incurring financing costs and with no specific form of financing obtained to finance plan contributions, they are financed with the Company's blended capital structure. Therefore, I recommend that the Commission continue to allow the return to be set at the Company's weighted average cost of capital.

Pension and Other Postretirement Costs Conclusion

Q. What are your final recommendations related to pension and other postretirement cost matters?

A. I recommend the Company be allowed to recover its net periodic pension and other postretirement costs and pension settlement losses based on the level of expense projected in the test period, as well as be allowed to continue to earn a return on its net prepaid pension and other postretirement asset based on the Company's weighted average cost of capital.

Alternatively, I recommend the Commission authorize a balancing account for all pension and other postretirement costs, including events such as pension settlements, with any resulting regulatory asset or liability being included in the net prepaid pension and other postretirement asset at the Company's weighted average cost of capital. If the Commission authorizes a pension and other postretirement balancing account, I recommend revenue requirement be established based on the net periodic benefit cost and settlement loss included in the Company's test period in this proceeding.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Rocky Mountain Power
Exhibit RMP___(NLK-1RR)
Docket No. 20-035-04
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Nikki L. Kobliha

Net Prepaid Impact on Revenue Requirement

October 2020

Exhibit RMP__(NLK-1RR)

Docket No. 20-035-04/Rocky Mountain Power

Historic pension and postretirement prepaid (accrued) balances and what the impact to revenue requirement would have been if the Company's current proposal was in place

Dollars in millions

Fiscal Period Ending	Subtotal**	2014	2015	2016	2017	2018	2019	Total
Total Company* **								
Prepaid/(accrued) pension balance		$ 304.8	$ 286.3	$ 273.1	$ 335.3	$ 331.8	$ 345.1	
Pension accumulated deferred income taxes		(116.0)	(108.6)	(103.6)	(127.3)	(81.6)	(84.8)	
Net pension prepaid(accrued)		$ 188.8	$ 177.6	$ 169.4	$ 208.1	$ 250.2	$ 260.2	
Prepaid/(accrued) other postretirement balance		$ (40.5)	$ (31.9)	$ (22.4)	$ (10.8)	$ 3.2	$ 10.3	
Other postretirement accumulated deferred income taxes		14.5	13.2	9.4	5.9	(0.3)	(2.1)	
Net postretirement prepaid(accrued)		$ (26.0)	$ (18.8)	$ (12.9)	$ (4.8)	$ 2.8	$ 8.1	
Net prepaid (accrued), after tax		$ 162.8	$ 158.9	$ 156.5	$ 203.2	$ 253.1	$ 268.3	
Utah allocated								
Utah allocation percentage		42.998%	43.273%	42.754%	43.114%	43.287%	43.064%	
Utah's allocated net prepaid(accrued), after tax	$ 72.8	$ 70.0	$ 68.7	$ 66.9	$ 87.6	$ 109.5	$ 115.6	
Authorized return on rate base****		10.774%	10.665%	10.665%	10.665%	9.222%	9.222%	
Revenue Requirement	$ (1.9)	$ 7.7	$ 7.4	$ 7.2	$ 8.2	$ 9.1	$ 10.4	$ 48.2

NOT ADJUSTED FOR TIME VALUE OF MONEY

*Shaded amounts are from Exhibit DKS-1R to Doug Stuver's rebuttal testimony in the last general rate case in Docket No. 13-035-184 ending with 2013, which was the final period with actual balances available at the time.

**Cumulative revenue requirement from earliest date information available through 2013, the latest date for which actual balances were available at the time of the last general rate case.

***For simplicity, includes total co view from 2014 through 2019 and thus includes some relatively minor deferral balances associated with other jurisdictions.

****For simplicity, derived from results of operations calculations for 2014 through 2019.

Average after-tax net prepaid 1993 through 2013	$ 2.2
Average after-tax net prepaid 1998 through 2013	$ 7.7
Average after-tax net prepaid 2014 through 2019	$ 200.5

Rocky Mountain Power
Docket No. 20-035-04
Witness: Rick T. Link

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Rebuttal Testimony of Rick T. Link

October 2020

Q. Are you the same Rick T. Link who previously provided direct testimony in this proceeding on behalf of PacifiCorp d/b/a Rocky Mountain Power ("PacifiCorp" or the "Company")?

A. Yes.

I. PURPOSE AND SUMMARY OF REBUTTAL TESTIMONY

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony supports the Company's position on the wind repowering projects and the Pryor Mountain wind project. Specifically, I respond to:

- The recommendation by witness Mr. Philip Hayet on behalf of the Office of Consumer Services ("OCS") that Foote Creek I repowering costs be removed from the test year and excluded from the Company's rate base.[1]
- The recommendation by Mr. Hayet that the costs of the Pryor Mountain wind project be removed from the test year and excluded from the Company's rate base.[2]
- Testimony from Dr. Joni Zenger on behalf of the Division of Public Utilities ("DPU") that the Company should exclude renewable energy credit ("REC") benefits from the calculation of net benefits for the Pryor Mountain wind project.[3]
- Mr. Kevin C. Higgins's recommendation that the terminal value for the Pryor Mountain wind project facilities be eliminated from the calculation of net benefits for the project.[4]

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[1] Direct Testimony of Philip Hayet at lines 82-96.
[2] *Id.* at lines 98-107.
[3] Direct Testimony of Dr. Joni S. Zenger at lines 26-32.
[4] Direct Testimony of Kevin C. Higgins at lines 803-815.

- Mr. Higgins's recommendation that the Pryor Mountain wind project be treated like a power-purchase agreement ("PPA"), with the pricing set at avoided-cost prices prepared for precursor qualifying facility ("QF") projects.[5]

Q. Please summarize your rebuttal testimony.

A. My rebuttal testimony addresses criticisms raised by Mr. Hayet, Dr. Zenger, and Mr. Higgins regarding the Company's proposed treatment of wind repowering projects, as well as the Pryor Mountain project. My rebuttal testimony demonstrates that:

- The Foote Creek I repowering project will generate net benefits for customers, and the Company's decision to move forward with that project was prudent. The costs of the project should therefore be included in base rates.
- The economic analysis for Foote Creek I should not be reconfigured to account for current market conditions or the COVID-19 pandemic, as Mr. Hayet suggests.
- The Company's economic analysis of the Pryor Mountain wind project demonstrates that the project will generate net benefits for customers, and the Company's decision to move forward with that project was prudent. The costs of the project should therefore be included in base rates.
- The calculation of net benefits for Pryor Mountain appropriately included REC benefits backed by an executed contract that establishes the term, volume, and price for REC sales.
- The Company's estimates of the terminal value of the Pryor Mountain project are not speculative and should appropriately be included in the calculation of customer benefits for the project.

[5] *Id.* at lines 880-945.

- Mr. Higgins's comparison of QF pricing to the Pryor Mountain project costs included in the Company's filing is inappropriate.
- The Pryor Mountain project should not be treated as a PPA as Mr. Higgins suggests because it is a Company-owned generating asset that should, as is the case with all generating assets, be appropriately included in rate base.

II. FOOTE CREEK I REPOWERING PROJECT

Q. What is Mr. Hayet's primary objection to including the Foote Creek I repowering project costs in the test year and base rates?

A. Mr. Hayet expresses concern with the turbines used in the Foote Creek I project and the manner in which the Company acquired the turbines.[6] This concern is addressed in the rebuttal testimony of Mr. Timothy J. Hemstreet. Regarding the economics of the Foote Creek I repowering project, Mr. Hayet contends that the project is likely to show only modest benefits, particularly in light of the COVID-19 pandemic and ensuing economic recession. He also criticizes the Company for not updating its economic analysis for the Foote Creek I project or demonstrating that it was among the "least cost options."

Q. What is your response to Mr. Hayet's economic arguments?

A. The Foote Creek repowering project is expected to generate substantial customer benefits. Specifically, my economic analysis demonstrates that Foote Creek I will deliver present-value net customer benefits ranging from $6 million to $48 million under two different price-policy scenarios. My analysis projects net benefits of $29/MWh in the expected case, which assumes medium natural gas and medium CO_2

[6] Direct Testimony of Philip Hayet at lines 478-535.

prices. On a per-megawatt-hour basis, the Foote Creek I repowering project is expected to match or beat the base case economics of nine out of 12 of the wind repowering projects the Commission approved in Docket No. 17-035-39.[7] As I explained in my direct testimony, the Foote Creek I repowering project is expected to generate net benefits even in the most conservative price-policy scenario, where it is assumed that natural gas prices will remain suppressed through the *entire* life of the project and there will *never* be a policy that imputes a charge on CO_2 emissions. If gas prices actually rise, or if a CO_2 policy is implemented that imputes a charge on emissions exceeding those assumed in the expected case, the project will be even more beneficial for customers. None of the modeled scenarios projected Foote Creek I will result in a net cost to customers, and Mr. Hayet does not provide any economic analysis showing otherwise. Because the project is expected to result in net benefits to customers, even when applying the most conservative price-policy assumptions, it was prudent for the Company to proceed with repowering.

Q. How do you respond to Mr. Hayet's criticism that the Company has not updated its economic analysis for Foote Creek I since July 16, 2019?[8]

A. My testimony presents the economic analysis that the Company relied on when it made the decision to proceed with the Foote Creek I repowering project. I understand that this is the relevant timeframe for the Commission to assess the prudence of the Company's decision. That analysis followed the same approach the Company used for other repowering projects that have been reviewed and approved by the Commission.

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[7] *In the Matter of the Voluntary Request of Rocky Mountain Power for Approval of Resource Decision to Repower Wind Facilities*, Docket No. 17-035-39, Report and Order (May 25, 2018).
[8] Direct Testimony of Philip Hayet at lines 523-535.

This is not to say that the projects would be uneconomic if later analyses were also performed. The Company has every reason to believe that the Foote Creek I repowering project will be beneficial to customers. In fact, as noted above, under even the most conservative application of price-policy assumptions, the project is expected to deliver customer benefits. I reject Mr. Hayet's contention that the Company must continually re-run economic analyses after the Company made its well-informed and reasonable decision to move forward with repowering Foote Creek I. The outcome of such an analysis would not have altered the Company's decision to move forward with the project, which had already been made. Moreover, I have no reason to believe that such an analysis would have suggested the decision to repower Foote Creek I was a bad or imprudent decision. Economic conditions are constantly changing, and Mr. Hayet presents no analysis that shows the project will be uneconomic due to the pandemic.

Q. How do you respond to Mr. Hayet's criticism that the Foote Creek I repowering project was not among the "least cost" alternatives?[9]

A. As an initial point, I reiterate that, on a per-megawatt-hour basis, the Foote Creek I repowering economics match or beat the base case economics of nine out of 12 the wind repowering projects the Commission approved in Docket No. 17-035-39, and is expected to generate net benefits even in the most conservative price-policy scenario. Further, Mr. Hayet's analysis is flawed because his approach does not focus on the prudence of the Company's decision at the time when it was made. While I am not a lawyer, I understand that a prudence determination looks at whether the decision to proceed with the project was reasonable as of the time the action was taken, in light of

[9] *Id.* at lines 645-661.

knowable risks, and not simply whether it was the lowest cost alternative. The Company has demonstrated that repowering Foote Creek I will generate net value for customers by comparing cases with and without the Foote Creek I repowering project. These cases consider the wide range of resource alternatives that are used to develop the Integrated Resource Plan ("IRP"), and the case with the Foote Creek I repowering project is lower cost and lower risk than the case without the Foote Creek I repowering project.

Q. How do you respond to Mr. Hayet's concern that the benefits of the Foote Creek I repowering project are likely to be smaller than your analysis suggests in light of the COVID-19 pandemic?[10]

A. Mr. Hayet's concern is unsupported. He provides no basis to assume that the current pandemic will alter the long-term economic performance of Foote Creek I. As noted above, I have no reason to believe that the benefits of the Foote Creek I repowering project will be diminished by the COVID-19 pandemic. The pandemic has no impact on wind generation, and customers will benefit from federal production tax credits ("PTCs") and zero-fuel cost energy regardless of the pandemic. Moreover, the pandemic occurred long after the Company prudently made its decision to proceed with the Foote Creek I repowering project

Q. Do you agree with Messrs. Hayet and Higgins that the low gas, no CO_2 price-policy scenario (the "LN scenario") in your analysis reflects current market conditions and should be given greater weight?

A. No, it is misleading to suggest that the LN scenario in my analysis reflects current

[10] *Id.* at line 531.

market conditions and therefore should be adopted as the most-likely scenario. The LN scenario assumes *sustained* suppressed prices for the entire life of the project. It is, in other words, a worst-case scenario analysis, not the likely scenario. It would be inappropriate to assume that the worst-case scenario will define market conditions for the entire life of the Foote Creek I repowering project.

III. PRYOR MOUNTAIN AND WIND REPOWERING PROJECTS

Q. How do you respond to Mr. Hayet's criticism that the benefits of the Pryor Mountain project are negligible in relation to the project cost under the LN scenario?[11]

A. The LN scenario is the most conservative, worst-case scenario, yet it still produces net benefits to consumers. As explained above, the LN scenario assumes sustained suppressed prices for the entire life of the project, which is unlikely. Given that the Pryor Mountain project will produce net benefits to customers, even in the worst-case scenario, it was prudent for the Company to pursue the project. Further, Mr. Hayet improperly suggests that there is no net benefit to customers when he states that the benefits of the Pryor Mountain project are negligible in comparison to the cost of the project. My analysis focuses on *net* benefits, which are the benefits to customers *taking into account the costs of the project*. There is no requirement that the net benefits exceed a certain amount of the costs of the project. Because the project provides net benefits to customers, customers are better off with the project than without it, even factoring in the costs of the project.

[11] *Id.* at lines 572-644.

Q. What is Dr. Zenger's recommendation for the Pryor Mountain wind project?

A. Dr. Zenger claims that the Company should calculate the net benefits from the Pryor Mountain wind project without including REC benefits.

Q. Was it appropriate to include the REC benefits for the Pryor Mountain wind project in the calculation of the net benefits of that project?

A. Yes. It is appropriate to include the revenues from REC sales in the calculation of net benefits because the Company has an executed contract with a buyer that sets the price and the term of the REC sales. It would only be appropriate to exclude revenues from REC sales if those sales were not tied to a specific contract. Here, the revenue received from the REC sales are more than just "upside" because they are tied to an executed contract.

Q. Why did you separate out the RECs in your Energy Vision 2020 testimony?

A. In my Energy Vision 2020 testimony, I calculated the customer benefits for the wind projects and did not include RECs in that analysis because, unlike here, the Company did not have an executed contract for the REC sales that set forth the actual terms and price.

Q. Do you intend to update your Table 4 results with the REC benefits stated separately, as Dr. Zenger suggests?

A. No, this would be inappropriate for the reasons stated above. My workpapers show the value of the REC sales, so this analysis can be performed by reference to the workpapers, to the extent Dr. Zenger believes it is relevant.

Q. How do you respond to Dr. Zenger's concern that the Pryor Mountain wind project does not result from a near-term energy or capacity need?[12]

A. The Company's recent IRPs show that the Company has a need for new resources to meet near-term energy and capacity needs. The Pryor Mountain wind project contributes to meeting those capacity shortfalls. Dr. Zenger is simply incorrect.

Q. Why was the Pryor Mountain wind project not included in the 2017 IRP?

A. The Company did not make its decision to build the Pryor Mountain wind project until long after the 2017 IRP was filed, so there would have been no reason to include this wind facility in the 2017 IRP. The 2017 IRP identified a resource need that could be met, in part, with PTC-eligible wind resources. Consequently, the 2017 IRP action plan included an action item to issue a request for proposals to acquire new wind resources. Ultimately, the Company issued the 2017R request for proposals ("RFP") (and subsequently, an RFP seeking bids for solar resources—the 2017S RFP) to procure new resources consistent with the 2017 IRP. At that time, the Company did not have development rights to offer Pryor Mountain into the RFP as a benchmark. At that time, the project was known as Bowler Flats, and the Bowler Flats project, which was owned by third-party, was not selected to the 2017R RFP final shortlist.

Q. Is Dr. Zenger correct that the Pryor Mountain wind project was not included in the 2019 IRP?

A. No. In the May 2019 public-input meeting for the 2019 IRP, the Company began presenting resource portfolio results that included 240 MW of new wind resources in eastern Wyoming by the end of 2020—a wind resource that would contribute to

[12] Direct Testimony of Dr. Joni S. Zenger at line 278.

meeting projected resource needs. Around that time, the Company communicated to its 2019 IRP stakeholders that there remained limited opportunities to acquire wind resources that would not require significant incremental transmission upgrades and that could still come online by the end of 2020 to qualify for the 100 percent PTC. The Company also communicated to its stakeholders that a competitive solicitation process could not be implemented in a time frame that would enable procurement of such a resource. The Company further communicated to the IRP stakeholders that it was, in fact, evaluating opportunities to procure this type of resource outside of a competitive solicitation process, particularly given the fact that the proxy PTC-eligible resource was consistently showing up in draft resource portfolios being developed for the 2019 IRP.

This is precisely what ultimately occurred. By the September 2019 public-input meeting, the near-term 240 MW proxy wind resource was no longer being presented in the draft resource portfolios because the transactions enabling the Company to build the project had been finalized. Pryor Mountain was subsequently included in all of the portfolios evaluated as part of the 2019 IRP in the same way that the Company's Energy Vision 2020 wind projects were included in all 2019 IRP resource portfolios. Consequently, Pryor Mountain is contributing to meeting the Company's resource needs and there is no doubt that this project was included in the 2019 IRP.

Q. Has the Company provided evidence demonstrated that the Pryor Mountain wind project is the least-cost, least-risk option for customers?

A. Yes. My economic analysis compares a case where the Pryor Mountain wind project is built to a case where the Pryor Mountain wind project is not built. In both of these cases, the *all* resource alternatives used to develop the IRP are available and evaluated to establish the least-cost combination of resources needed to reliably serve customers. These resource alternatives include an assessment of incremental energy efficiency and demand-side management programs, market purchases, gas-fired resources, wind resources, solar resources, battery storage resources, and pumped storage resources. My economic analysis shows that the case with Pryor Mountain generates lower system costs than the case without Pryor Mountain when considering all of these different resource options. Moreover, this analysis considers how stochastic risks, like volatility in natural gas prices, volatility in energy prices, volatility in load, volatility in hydro generation, and uncertainty with generator outages affects system costs in both cases (with and without Pryor Mountain). My analysis also evaluates price-policy risks related to long-term forecasts of natural gas prices and CO_2 prices. As already stated, this price-policy analysis shows that Pryor Mountain is least cost and least risk relative to a wide array of alternative resource options even in the most conservative LN scenario.

Q. Dr. Zenger further questioned the validity of including REC's in your analysis because the Company's Schedule 272 Agreement with Vitesse expires in 25 years, while the depreciable life of the Project is 30 years. Is the value of Pryor Mountain uncertain for the last five years of Project life?[13]

A. No. As indicated in my direct testimony, the Company entered into a very favorable contract with Vitesse, which requires it to purchase all of Pryor Mountain's REC credits for 25 years. Our PaR value that was included in our initial filing, and which

[13] Direct Testimony of Dr. Joni S. Zenger at lines 159-168.

demonstrates the considerable and robust economic value of the Project, only includes REC sales that are subject to written contracts. The value of this Project is not contingent on further REC revenues in years 26-30.

Q. Do you agree with Dr. Zenger that REC uncertainties, including but not limited to the duration of the Vitesse contract, suggest that the Company should be required to provide a separate economic forecast without REC credits included in the calculation?

A. No. As we have stated, the Company only included the economic impact of REC credit sales that are subject to binding written agreement. There is nothing speculative or uncertain about those values. Further, the Company ran two separate PaR simulations—one with incremental generation and one without—and neither simulation is impacted by potential swings in REC credit values.

Q. What is Mr. Higgins's concern with your economic analysis of the Pryor Mountain wind project?[14]

A. Mr. Higgins expresses concern with the terminal value of $106.7 million used for the Pryor Mountain wind project facilities. Mr. Higgins claims that this terminal value is speculative and argues that the net benefits of the project are negative if the terminal value is removed from the calculation.

Q. How do you respond to Mr. Higgins's testimony that the terminal value used in your analysis of Pryor Mountain is speculative?

A. The Company's estimates of the terminal value of the Pryor Mountain project are not speculative and should appropriately be included in the calculation of customer benefits

[14] Direct Testimony of Kevin C. Higgins at lines 805-815.

for the project. Terminal value includes three reasonably estimated components. The first component is for value associated with transmission assets remaining at the end of the assumed life for the generating resource. This is calculated as the remaining net book value adjusted for inflation at the time the generating resource is assumed to retire. The second component represents the value of non-transmission assets remaining at the end of the assumed life of the generating resource (*i.e.*, roads, buildings, land, etc.). This is fully depreciated at the end of the resource's 30-year book life; however, it has a terminal value because the cost of these assets would not need to be incurred by a successor project or could be sold for value in exchange. Therefore, the terminal value is equal to the original cost adjusted for inflation multiplied by the portion of the original life remaining (50 percent). The third component represents the value of development rights which is escalated from the current value at inflation. The Company's valuation properly included values for each of these items in deriving the terminal value at issue. That process was no different from the Company's inclusion of terminal value in other benefit calculations performed for other utility assets in other matters, and Mr. Higgins does not claim otherwise. Mr. Higgins's criticism that the terminal value benefit is speculative and should be excluded merely because it based on a 30-year forecast is also illogical. The Company performs that same kind of forecast when it estimates benefits related to assets in many settings. When it does so, the Company checks the derived value under various analyses to test the expected benefits over a range of potential future scenarios to arrive at a reasonable estimated value range. The Company followed that same process with the Pryor Mountain project. The Company's decision to move forward with Pryor Mountain was based on the best information available at the time, including the best forecasting information available to it, and the value range derived from the Company's analyses shows that the project is expected to generate significant customer benefits over time.

Q. Is it appropriate to remove the terminal value from the analysis of net benefits?

A. No. The terminal value included in the Company's analysis recognizes that, at the end of a utility-owned resource's life, there is residual value in the asset that accrues to customers. In determining the benefits of a utility asset, it is common practice to include a terminal value, even where that value may be years into the future. The terminal value includes the facilities supporting the resources, such as transmission facilities, that have longer useful lives and, in the case of generation tied to natural resources such as wind resources, there is inherent value in the site and property itself—particularly resources located in high-capacity-factor geographic areas like Montana. High-value, renewable-resource locations are often scarce or unique in their suitability for generation permitting and construction, as well as proximity to transmission. For a PPA, the terminal value accrues to the project owner, not customers. But for a utility-owned resource, retail customers retain the value of these assets at the end of the project's life. The Company's calculation of the terminal value benefit for the Pryor Mountain project should be included in the analysis. Furthermore, even if the terminal value benefit were eliminated from the analysis, which would not be appropriate, the Pryor Mountain project is still forecast to provide net customer benefits under the medium natural-gas scenario before accounting for all of the conservative assumptions used in the Company's economic analysis.

Q. Does Mr. Higgins provide any evidence to support his claim that the terminal value used by the Company is highly speculative?

A. No. Mr. Higgins simply claims the benefits calculated by the Company are speculative because of the period of time over which those benefits are expected to occur. He provides no independent valuation or analysis that challenges any of the assumptions, scenarios or inputs used in the benefits calculation.

Q. Please describe Mr. Higgins's proposal for the Company's recovery of Pryor Mountain costs.[15]

A. Mr. Higgins claims the Pryor Mountain project is imprudent, not on the basis of a lack of customer benefits, which he acknowledges exist, but rather because the Company-developed cost of the project exceeds the indicative, per megawatt-hour ("MWh") avoided-cost pricing previously provided to several QFs proposed by a third-party developer that were the precursors of the Pryor Mountain project. He recommends that the project be treated like a PPA, with the pricing set at that stale indicative avoided-cost pricing prepared for those precursor QF projects. Consistent with and as a part of the PPA treatment proposed by Mr. Higgins, the Company would also retain the RECs and PTCs produced by the Pryor Mountain project.

Q. Is Mr. Higgins's comparison of a QF PPA price to the project cost relevant or valid?

A. No. There are numerous differences between the QF pricing and the valuation as a Company-owned resource, none of which are addressed by Mr. Higgins. First, the QF pricing cited by Mr. Higgins is based on 20-year contract, while I used the 30-year life

[15] Direct Testimony of Kevin C. Higgins at lines 886-896.

of the assets when I conducted my analysis of the Pryor Mountain project. Mr. Higgins is not accounting for the additional 10 years of value to customers in his comparison, which makes his analysis inaccurate. Extending the QF pricing Mr. Higgins relies on over a 30-year period, rather than the 20-year period he uses, alone would increase the nominal levelized value to $29.19/MWh from December 2020 to through November 2050.

Second, the location of Pryor Mountain is important to the valuation. Because it is a significant distance from other wind resources, the generation profile is different from other wind resources, and it provides additional value to customers by way of diversifying the Company's wind production. Third, Mr. Higgins uses avoided cost pricing developed with data from the Company's 2017 IRP. The data used in my economic analysis in this proceeding is based on more current data. Fourth, Mr. Higgins ignores that the methodology used to arrive at avoided cost pricing is different from the methodology I used to calculate the value of the Pryor Mountain project for purposes of this docket. The avoided cost pricing to which Mr. Higgins cites is based on a QF analysis that not only relied on dated information and assumed the deferral of 2030 wind, the analytical methods used to establish avoided cost prices are a proxy of the more robust type of analysis used to support the project economics of Pryor Mountain in this proceeding. My analysis was based on then-current data that was assessed under a dynamic portfolio re-optimization approach that included a reliability assessment—the avoided cost pricing methodology does not capture portfolio re-optimization nor does it include an assessment of system reliability. My analysis is therefore not only more current, but also more robust.

Fifth, Mr. Higgins ignores the additional benefits to customers that come from a Company-owned resource. The Company retains flexibility and control in operating and dispatching the resource and avoids the risks associated with contracted QFs, such as credit risk. With a QF resource, the Company has no ability to control the dispatch of that resource and must simply pay for power provided to it regardless of whether that power is economic or not. Furthermore, as I explained above, customers continue to receive the benefits of that resource for as long as it operates and even after the resource is no longer operational, because customers retain the value associated with the land and facilities that remain beyond the depreciable life of the generating resource. In short, Mr. Higgins is conducting an apples-to-oranges comparison when he compares 20-year avoided-cost pricing to the 30-year, more robust and more current economic analysis provided with my direct testimony.

Q. Mr. Higgins recommends that the Pryor Mountain project be treated essentially as a PPA. Do you agree with this approach?

A. No. Mr. Higgins's suggestion is inconsistent with my analysis and with the manner in which Company-owned resources are handled. The Pryor Mountain project investment is not a PPA; it is a Company-owned resource and traditional rate base item. Mr. Higgins does not provide any legitimate basis for his proposal, which would be a vast departure from historical regulatory treatment. Mr. Higgins's recommendation is effectively a disallowance for a prudent investment.

Q. Does this conclude your rebuttal testimony?

A. Yes.

REDACTED
Rocky Mountain Power
Docket No. 20-035-04
Witness: Robert Van Engelenhoven

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Rebuttal Testimony of Robert Van Engelenhoven

October 2020

Q. Are you the same Robert Van Engelenhoven that filed direct testimony on behalf of PacifiCorp d/b/a Rocky Mountain Power ("Rocky Mountain Power" or the "Company") in this proceeding?

A. Yes.

I. PURPOSE OF REBUTTAL TESTIMONY

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is two-fold. First, I provide a construction update regarding the Pryor Mountain Wind Project. Second, I respond to the testimony of Division of Public Utilities ("DPU") witness Dr. Joni S. Zenger and Office of Consumer Services ("OCS") witness Mr. Philip Hayet regarding the Pryor Mountain Wind Project.

II. PRYOR MOUNTAIN WIND PROJECT

Q. What is the current construction status of the Pryor Mountain Wind Project?

A. The Company has received notices from most suppliers and contractors providing materials or service for the Pryor Mountain Wind Project, in which they generally claim delays due to disruption to the global supply chain caused by the COVID-19 pandemic. PacifiCorp also continues to review the information provided by suppliers and contractors as the situation with the pandemic continues to evolve. Our primary focus has been to ensure the safety of the workers at the site by following the guidelines established by the Centers for Disease Control and Prevention to control the spread of the COVID-19 virus. To date we have had no confirmed cases of the COVID-19 virus within the workforce at the Pryor Mountain Wind Project.

The wind turbine components supplier, Vestas-American Wind Technology, Inc. ("Vestas"), has provided notice of delayed deliveries of all wind turbine components due to the force majeure event. Wind turbine component delivery has been a particularly dynamic situation. In July 2020, some of the supply and transportation issues started to stabilize and Vestas provided a schedule indicating that deliveries would be completed the week of November 23, 2020. This represented a six-week delay and pushed the construction of the project well into the high-wind, winter period. To work safely, wind turbine construction cannot take place with wind speeds over 25 miles per hour, thus limiting the time available to work due to increased daily wind speeds starting late in September. The Company negotiated a change order with Vestas to adjust the schedule to complete the wind turbine component deliveries by the week of November 2, 2020. This revised schedule has been forwarded to the balance of plant ("BOP") contractor so that they can update their costs and schedule. The Company continues to negotiate the revised costs and schedule with the BOP contractor, with an objective to economically place in-service as many of the wind turbines as possible in 2020. The plan in development includes utilizing wind turbine pre-commissioning by the wind turbine supplier and placing the project's 12 collector circuits in-service circuit by circuit instead of all at one time. Through this effort the Company is forecasting that circuits 1-8 (160 megawatts ("MW")) can be placed in-service in 2020, and circuits 9-12 (80 MW) can be placed in-service by the end of the second quarter 2021. The actual megawatts placed in-service in 2020 and 2021 are contingent on the weather conditions. Placing the project in-service on a circuit by circuit basis, when transmission service is available,

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allows production tax credits ("PTCs") and energy from the project to flow to customers as soon as possible. The Company continues to work with suppliers and contractors to develop and revise costs and schedules to complete the construction of the Pryor Mountain project within the delays and uncertainties presented by the COVID-19 pandemic.

Q. Have the delays and uncertainties presented by the COVID-19 pandemic impacted the overall costs of the project?

A. Yes. The overall cost of the project has increased from a projected cost of [redacted], at the time of filing my direct testimony, to a current projected cost of [redacted] The scheduled completion has shifted from having 240 MW in service at the end of 2020, to having 160 MW in service by the end of 2020 and the remaining 80 MW in service by June 30, 2021. The full value of the PTCs have been preserved but the timing of the full benefit to customers for the final 80 MW has delayed to June 2021. The impact of the updated costs is included in the revenue requirement as discussed by Company witness Mr. Steven R. McDougal in his rebuttal testimony.

Q. Have the delays and uncertainties presented by the COVID-19 pandemic impacted the customer benefits you presented in your direct testimony in this proceeding?

A. No, only the timing. The full value of the PTC's, RECs, and customer benefits have been preserved; however, with 160 MW being placed in service in 2020, and the remaining 80 MW being placed in service by June 30, 2021, the timing for receiving the full benefits of the project has been altered. As discussed by Company witness

Mr. Rick T. Link, even with the increased costs and delayed benefits, the project still delivers significant benefits to customers, is prudent, and benefits Utah customers.

Q. Please summarize the recommendation of DPU witness Dr. Zenger with respect to the Pryor Mountain project?

A. Dr. Zenger recommends the Commission reject the Company's request for recovery of Pryor Mountain at this time, a recommendation she states she may change upon evaluating additional economic analysis. Mr. Link addresses her economic benefits recommendations in his rebuttal testimony. Dr. Zenger also claims that the Company circumvented Integrated Resource Plan regulatory processes and mentions several examples of risks she claims could affect the ability of the project to qualify for full PTCs. Mr. Link addresses Dr. Zenger's claim regarding the regulatory process and I address her concerns about impacts on the project from delays.

Q. Do you agree with Dr. Zenger that any type of delay that affects the December 31, 2020 deadline to qualify for full value of the PTCs is a risk of the Pryor Mountain Wind Project?[1]

A. No. The Internal Revenue Service ("IRS") issued revised guidance regarding the commercial operation date of projects qualifying for PTCs. Specifically, in May 2020, the Continuity Safe Harbor was extended to five calendar years for projects that began construction in 2016 or 2017.[2] Pryor Mountain has a 2016 start of construction date. Accordingly, the continuity requirement will be met if the project is placed in-service by December 31, 2021, and the project will qualify for 100 percent PTCs. As I explained above, about 67 percent of the project is forecasted to be placed

[1] Direct Testimony of Joni S. Zenger at 17 (DPU Exhibit 8.0 DIR).
[2] Internal Revenue Service Notice 2020-41 (May 27, 2020). See, https://www.irs.gov/pub/irs-drop/n-20-41.pdf.

in-service by December 31, 2020 with the remainder of the project to be place in-service by the end of the second quarter 2021. Thus, the project continues to qualify for 100 percent PTCs under IRS guidance until December 31, 2021.

Q. Dr. Zenger specifically identifies risks such as inclement weather, construction delays and labor shortages. Given the fact that some of these risks have actually been realized to some extent due to the COVID-19 pandemic, how do you respond to Dr. Zenger's claims that risks, such as these, should be not be "on the backs of Utah customers"[3]?

A. I disagree that weather, construction, and labor risks have been shifted to Utah customers. As I explained above, the Company has been working with its supplier and construction contractors to mitigate the impacts of the delays that have been attributed to the COVID-19 pandemic. The Company has worked diligently to minimize the impacts on costs and construction as a result of the delays that were beyond its control. As a result, the Company forecasts that circuits 1 through 8 of the project will be placed in-service by the end of 2020 and circuits 9 through 12 will be in-service by the end of the second quarter 2021. Based upon the revised guidance from the IRS, the Pryor Mountain Wind Project continues to qualify for 100 percent PTCs.

Q. Please summarize the recommendation of OCS witness Mr. Philip Hayet with respect to the Pryor Mountain project?

A. OCS witness Mr. Hayet asserts that the Company's acquisition and its use of disparate types of wind turbine generators ("WTGs") acquired from Berkshire Hathaway Energy Renewables ("BHER") appears to have been negotiated so BHER

[3] Direct Testimony of Joni S. Zenger at 360.

could use its and the Company's remaining WTG equipment stocks before the PTCs started phasing out and before BHER and the Company's pre-purchased inventory of WTGs started losing value.[4] [5]

Q. How do you respond?

A. I disagree with Mr. Hayet's unsupported assertion. PacifiCorp will receive Vestas V110 2.0-2.2 MW wind turbine components (specifically nacelles and hubs) from BHER. This transaction was contemplated due to the limited availability and pricing volatility of turbine equipment in the market in 2019 as a result of high demand and limited supply of equipment that could be installed in 2020 to qualify for the full value of available federal wind energy PTCs, and the late-stage development and time-limited nature of the Pryor Mountain Wind Project. The market of available wind turbines was further constrained by the equipment available to erect the wind turbines. The class of large cranes required to erect higher capacity wind turbines were not available, limiting the selection of turbines that could be constructed at the Pryor Mountain Wind Project to certain turbines. PacifiCorp's economic analysis for the project included utilizing the BHER turbine components at the costs included in the Purchase and Sale Agreement with BHER's wholly-owned subsidiary, BHE Wind, LLC, and found the Pryor Mountain Wind Project provided significant customer benefits. PacifiCorp secured the benefits of the project for customers by acquiring the components from BHER and avoided equipment supply limitations, construction issues, and price volatility. As PacifiCorp was planning for the Pryor

[4] Direct Testimony of Philip Hayet at 24-25 (Witness OCS – 4D).
[5] *Miscellaneous Correspondence and Reports Regarding Electric Utility Services: 2020*, Docket No. 20-99-02, Redacted PacifiCorp's Notice of Affiliate Transaction with BHE Wind, LLC, Safe Harbor PTC Components (July 2, 2020).

Mountain Wind Project, PacifiCorp was also in the process of procuring numerous other turbines for the Energy Vision 2020 projects and the Foote Creek I repowering project. Based on PacifiCorp's experience in bidding those projects, the Company observed price volatility and there were concerns regarding the ability of suppliers to meet the overall market demand and supply turbines for the entire project in a timeframe that would achieve commercial operation before January 1, 2021, as required to achieve full PTC benefits.[6] PacifiCorp had an opportunity to acquire components that were already manufactured and in storage from BHER at cost, which was the competitive market price at their time of purchase in 2016.

Thus, contrary to Mr. Hayet's assertion, the Company engaged in the transaction with BHER due to the limited availability and pricing volatility of turbine equipment in the market in 2019 and the transaction allowed it to ensure the qualification of the full value of available federal wind energy PTCs.

Q. Does this conclude your rebuttal testimony?

A. Yes.

[6] In response to the COVID-19 pandemic, the Internal Revenue Service recently issued Notice 2020-41 that provides a one-year extension of the continuity safe harbor, thus allowing wind energy facilities that began construction in 2016 to qualify for the full value of PTCs if placed in service before January 1, 2022.

REDACTED
Rocky Mountain Power
Docket No. 20-035-04
Witness: Timothy J. Hemstreet

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Rebuttal Testimony of Timothy J. Hemstreet

October 2020

Q. Are you the same Timothy J. Hemstreet who previously provided direct testimony in this case on behalf of PacifiCorp d/b/a Rocky Mountain Power ("PacifiCorp" or the "Company")?

A. Yes.

I. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. The purpose of my rebuttal testimony is to give an update on the construction progress and expenditures for the Energy Vision 2020 wind energy projects including TB Flats, Ekola Flats, and Cedar Springs II ("New Wind Projects") that were approved by the Public Service Commission of Utah ("Commission") in Docket No. 17-035-40. I also provide an update on the progress of construction of the Dunlap and Foote Creek I repowering projects. My rebuttal testimony also addresses certain recommendations made by the Office of Consumer Services ("OCS") witness Mr. Philip Hayet regarding the Foote Creek I repowering project.

Q. Please summarize your rebuttal testimony.

A. Wind turbine generator ("WTG") equipment deliveries from the predominant WTG equipment supplier, Vestas-American Wind Energy, Inc. ("Vestas"), have been delayed, which Vestas has attributed to the global COVID-19 pandemic. As a result, construction progress at the TB Flats and Ekola Flats wind projects have been impacted. The Company continues to work diligently with its suppliers and contractors to mitigate the impacts of these delivery delays and bring these beneficial projects online as soon as practicable while managing cost impacts associated with the extended construction schedule. To mitigate the impacts of these delays, the Company will place the New Wind Projects in-service in a phased approach. On the date that interconnection and transmission service is available to allow the energy to flow from the New Wind Projects to the transmission system, all WTGs on electrical circuits that are ready to be placed in-service will immediately begin operations. In circumstances where less than 100 percent of the WTGs are ready to be placed in-service on such date, the remaining WTGs will be placed in-service on a circuit-by-circuit basis. This plan allows customers to enjoy the energy and production tax credit ("PTC") benefits of the New Wind Projects as soon as possible. The Company has updated its forecasted costs for the New Wind Projects to reflect costs associated with addressing the impact of delayed equipment delivery and the resulting extended construction schedules for the facilities. The Company continues to work with suppliers and contractors to implement revised schedules to complete the construction of the New Wind Projects in the most cost effective manner. Because the full extent of the project delays continues to evolve, any incremental costs in excess of the updated amounts for the New Wind Projects included in the Company's rebuttal filing, if any, will be reflected in a future general rate case.

II. ENERGY VISION 2020 NEW WIND PROJECTS AND FOOTE CREEK I REPOWERING PROJECT CONSTRUCTION STATUS

Q. What is the current construction status of the TB Flats I and II wind facilities?

A. For the nominal 500 megawatt ("MW") TB Flats I and II wind facilities, all WTG foundations and access roads are complete. There are two collector systems in the project; the first collector system is complete, and all cabling for the second collector system has been laid. Terminations for the second collector system are nearing completion, and associated testing is underway as fiber installation continues to proceed. The first collector substation and backfeed power is complete, allowing WTG commissioning activities to proceed. The second collector substation is 80 percent complete; the step-up transformer has been placed with fencing, gravel and final testing remaining to be completed. The transmission line connecting the two collector substations is complete, as is the transmission line connecting the project to the Shirley Basin substation. WTG delivery and erection activities are continuing at the project with more than half of the WTGs now erected.

Q. What is the current construction status of the Ekola Flats wind facility?

A. For the nominal 250 MW Ekola Flats facility, all 63 foundations and access roads are complete; the collector system is complete; and the substation is now complete and able to provide backfeed power so that WTG commissioning activities can proceed. All General Electric safe harbor turbines have been erected and nearly all of these turbines have reached mechanical completion. All Vestas turbine deliveries have been completed, and those turbines are now being erected. The operations and maintenance building is nearly complete, and crews are focused on continuing erection and commissioning activities.

Q. What is the current construction status of the Cedar Springs II wind facility?

A. For the nominal 200 MW Cedar Springs II facility, the collector substation is nearly complete and soon will be able to be synchronized with the transmission grid. All of the 72 foundations have been completed, and WTG erection activities are proceeding. Backfeed power to WTGs will soon be available so that commissioning activities can proceed after WTGs achieve mechanical completion. Work on the collector system is approximately 80 percent complete and approximately 65 percent of the turbines have been erected.

Q. What is the construction status of the Foote Creek I repowering project?

A. Foundations for all 13 of the new WTGs are complete. The new switchgear building has been set and internal components are being assembled. The 68 original WTGs are dismantled and components are being hauled offsite. The new collection circuits have been placed and are now being prepared for testing. Duct work for the fiber communication system has been installed from the switchyard to the operations building. All WTG components have been delivered, and seven have been erected.

Q. What is the construction status of the Dunlap repowering project?

A. Construction efforts at the Dunlap project are complete. The repowered project was placed in service on September 7, 2020, completing construction at all of the facilities for which repowering was pre-approved in Docket No. 17-035-39. Final reclamation activities are now underway at the project site.

Q. Has the Company received force majeure notices from contractors that are involved in the equipment supply and construction of the New Wind Projects and Foote Creek I repowering project?

A. Yes. As a result of the COVID-19 pandemic, the Company has received force majeure notices from all of the major contractors involved in these projects.

Q. Has the COVID-19 public health emergency had a material impact on the Company's construction schedule for the New Wind Projects or the Foote Creek I repowering project?

A. First and foremost, the Company is working closely with its contractors and suppliers to ensure that work on these projects proceeds in a manner that protects the safety of the people working on the projects and the local public where the projects are located. Work at all projects is proceeding under COVID-19 mitigation plans to address worker health and safety. As mentioned above, the pandemic has resulted in force majeure notices and claims by all major contractors that the pandemic has disrupted the WTG supply chain and construction activities, resulting in delayed equipment deliveries, delivery of equipment that may occur out of sequence from originally planned deliveries, and slower than anticipated construction progress. At the TB Flats and Ekola Flats projects, equipment delivery delays have affected the construction schedules and turbine construction activities. At the Cedar Springs II project, equipment delivery delays have also occurred with the WTG equipment being supplied by General Electric, but work is underway to mitigate the impact of those equipment delays and achieve the project schedule. At the Foote Creek I repowering project, equipment delivery has not been significantly delayed, and work is underway to keep the project on schedule. Across all of the projects, delayed turbine deliveries and COVID-19 worker safety protocols have decreased productivity and affected production beyond the schedule delays associated with the WTG equipment supply.

The Company is working diligently with the equipment suppliers and balance of plant construction contractors to mitigate the impacts of delayed equipment delivery to the projects, and construction delays due to COVID-19 impacts, while ensuring that the people working on the projects and the general public in the communities hosting these projects are protected by complying with all governmental requirements, orders and directives. The Company and its contractors are also working to firm up schedules for remaining equipment deliveries and turbine erection and commissioning activities.

Q. Does the delay in the project schedules threaten the ability of the projects to qualify for production tax credits?

A. No. The Internal Revenue Service has issued a notice (Notice 2020-41) in response to the COVID-19 pandemic providing for a one-year extension in the Continuity Safe Harbor such that wind projects must be in-service prior to January 1, 2022, in order to qualify for the full value of PTCs.

Q. How will the construction delays affect the commercial operations dates for the New Wind Projects and Foote Creek I?

A. Although construction is delayed, I anticipate that the Ekola Flats, Cedar Springs II and Foote Creek I wind projects will still reach full commercial operation in late 2020. The network upgrades and new transmission line components of Energy Vision 2020 are proceeding on schedule and should allow all completed wind turbines for the New Wind Projects to be commissioned before the end of the year and their output delivered to the Company's customers. However, it is likely that the Company will be unable to commission as many as 45 of the 132 WTGs at TB Flats until late spring or early summer 2021. As a result, approximately 309 MW of TB Flats WTGs will be brought online in 2020 with the remaining approximately 194 MW of nameplate capacity coming online in 2021.

Q. Has the Company adjusted its approach to bringing the new WTGs into commercial operation as a result of the construction delays resulting from the COVID-19 pandemic?

A. Yes. Because transmission service will now be available before all of the WTGs at the TB Flats project are erected and commissioned, the Company now plans to bring the WTGs at the project into commercial operation on a circuit-by-circuit basis after the planned commercial operation date occurs. This means that rather than wait for all WTGs to be commissioned before the project achieves commercial operation (which was anticipated to occur just as the newly constructed transmission service was available), each circuit of WTGs at the project will be placed into commercial operation when all WTGs on each particular circuit have been commissioned and are ready to serve customers. Thus, a large number of WTGs will be placed in operation simultaneously in late 2020, and any WTGs that are not yet commissioned when transmission service is available will be brought into commercial operation when all the WTGs on a particular circuit are ready for commercial operation. Because high winds and weather conditions make wind energy construction in the high plains of southeast Wyoming difficult in the winter, construction efforts will largely cease in late November 2020 and resume when conditions are more favorable in the spring of 2021.

Q. What are the benefits of this strategy to bring turbines online on a circuit-by-circuit basis?

A. Customers will benefit by having the WTGs online sooner than might otherwise occur. In the case of TB Flats, customers will benefit from the zero-fuel cost energy from the projects as soon as those benefits are available, without waiting for every WTG at the project site to be completed.

Q. Is a circuit-by-circuit approach to commercial operation allowed under the Internal Revenue Service rules for qualifying WTGs for PTC benefits?

A. Yes. Internal Revenue Service guidance does not require that all WTGs on a project achieve commercial operation at the same time and placing WTGs online on a circuit-by-circuit basis is an approach that has been used by other Berkshire Hathaway Energy affiliates as well as other wind project developers.

Q. Has the Company updated its estimated costs for the New Wind Projects in its rebuttal filing?

A. Yes. The Company has included its most current project cost forecasts for the New Wind Projects in its rebuttal filing. Confidential Exhibit RMP___(TJH-1R) provides these updated forecasted amounts. Overall, project cost estimates for the New Wind Projects at the time of this filing have increased slightly by approximately [redacted], as compared to the forecast estimates filed by the Company with its direct testimony.

Q. Do the Company's updated cost estimates for the New Wind Projects include all cost adjustments related to the COVID-19 pandemic and the associated force majeure notices and claims by the Company's suppliers and contractors?

A. Not necessarily. The Company's updated cost estimates include known cost adjustments at the time of this filing. However, the Company continues to work with its suppliers and contractors to assess the ongoing delivery delays and associated construction impacts in order to adjust its plans to the situation and complete construction of the projects in the most cost effective manner. I anticipate that if costs of the New Wind Projects exceed the amounts included in the Company's rebuttal filing, the Company will seek recovery of those costs in a future rate case proceeding.

Q. The forecasted cost of the Cedar Springs II project has increased as compared to the amount contained in the Company's application. Can you explain the change in the forecasted project costs?

A. Yes. As I noted in the cost exhibit filed with my direct testimony (Exhibit RMP___(TJH-1)), the costs filed for the Cedar Springs II project in the Company's application included only the Build Transfer Agreement costs and did not include internal project management costs. This has now been updated in the Company's rebuttal filing and Cedar Springs II costs have increased by $[redacted] as a result, but remain $[redacted] below the pre-approved in-service cost.

Q. The forecasted cost of the TB Flats project has increased as compared to the amount contained in the Company's application. Can you explain this change?

A. As described above, due to equipment delivery delays and other delivery inefficiencies that have impacted construction progress on the project, construction efforts are now anticipated to extend into the 2021 construction season. As a result, the forecasted cost of TB Flats, as shown in Confidential Exhibit RMP___(TJH-1R), has increased by approximately $[redacted]. These costs are due to extended overheads, equipment costs, and administrative and labor costs associated with the longer duration of construction that are known and forecast at this time.

III. FOOTE CREEK I PROJECT RECOMMENDATIONS

Q. OCS witness Mr. Philip Hayet states that the use of the term "repowering" to describe the Company's efforts at the Foote Creek I project is "rather misleading"[1]? Do you agree?

A. No. The term "repowering" accurately reflects the Company's efforts at Foote Creek I. As used in the wind energy industry, the term "repowering" simply means replacing older wind turbines, or wind turbine components, at existing wind projects with newer technology while retaining the remainder of the site assets – including land and transmission rights, site roads, operations and maintenance facilities, and other project components. The Company's efforts fit this definition.

Q. Mr. Hayet states his concerns with the Foote Creek I project given that it was not considered in Docket No. 17-035-39, and that the Company proceeded with the Foote Creek I repowering project without any regulatory approval.[2] Should this be cause for concern?

A. No. The Company was not able to fully evaluate the Foote Creek I repowering project or agree upon necessary commercial arrangements to repower the facility until well after the Commission had rendered its decision in Docket No. 17-035-39. However, Action Item 1a of the 2017 Integrated Resource Plan ("IRP") committed the Company to evaluate repowering the Foote Creek I project, and the 2017 IRP Update included a Foote Creek I sensitivity that stated that repowering the project was likely to produce customer benefits. Finally, the Company did receive a Certificate of Public Convenience and Necessity from the Wyoming Public Service Commission to repower

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[1] Direct Testimony of Philip Hayet for the Office of Consumer Services, September 2, 2020, line 463.
[2] *Id.* at line 476.

the Foote Creek I facility, so the Company's efforts were not without regulatory visibility or scrutiny.

Q. Mr. Hayet raises concern that the Foote Creek I project will use some turbines acquired from Berkshire Hathaway Energy Renewables ("BHER") that were originally purchased in 2016 rather than "2020 model year WTGs."[3] Should this cause concern?

A. No. Consistent with IRS guidance, a taxpayer can establish the year in which a wind energy project begins construction through the purchase of wind turbine generator equipment that ultimately comprises at least 5 percent of ultimate project costs. A production tax credit ("PTC") "safe harbor" is created for wind facilities subsequently constructed using this equipment. This "safe harbor equipment' is then stored and maintained consistent with the manufacturer's specifications until it is ultimately installed at a wind project – which can occur up to five yearsafter the equipment was purchased, under current IRS guidance. The turbines acquired from BHER allow the Foote Creek I project to qualify as having begun construction in 2016, so the project qualifies for 100 percent of the value of the PTC. I imagine Mr. Hayet's concern about the vintage of the turbines acquired from BHER would not be alleviated had the Company acquired all "2020 model year WTGs" for the project consisting only of the larger 4.2 MW turbines and thereby qualify the project for PTCs at only 40 percent of their full value as a result of beginning construction of the project in 2019 when site

[3] *Id.* at lines 482-484.

work at the project began, rather than in 2016 when the "safe harbor" turbines were acquired.[4]

Q. Mr. Hayet raises a question about whether the turbines acquired from BHER were acquired "at the lesser of cost or fair market value."[5] Can you shed light on this?

A. Yes. The turbines were acquired from BHER at cost. There is no "market" for safe harbor turbines because safe harbor equipment cannot be transferred from one consolidated taxpayer to another and still retain its ability to qualify a wind project as having begun construction in a certain year. Because there was no market reference meaning safe harbor equipment could not be procured from the marketplace, the BHER turbines were acquired at BHER's cost.

Q. Mr. Hayet wonders why the Company felt the need "to rush into this project in 2019"[6] given the Company likely knew it would be soliciting additional renewable resources when it filed its 2019 IRP in October 2019. Why was the Company motivated to move forward when it did?

A. When the Company decided to move forward with repowering Foote Creek I in June 2019, it was understood that 100 percent PTCs would only be available for wind projects that reached commercial operation prior to January 1, 2021. Under the PTC rules that were in effect at that time, wind energy projects that would be solicited in a

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[4] On December 18, 2015, Congress enacted changes to the federal Internal Revenue Code extending the full value of the PTC for wind facilities that began construction in 2015 and 2016. The legislation also provided for a phase-out of the PTC over three years, reducing the PTC to 80 percent of the full value for wind facilities beginning construction in 2017, 60 percent for wind facilities beginning construction in 2018, and 40 percent for wind facilities beginning construction in 2019.

[5] Direct Testimony of Phillip Hayet, lines 508-509.

[6] *Id.* at lines 511-512.

future request for proposals would likely only be able to qualify for PTCs at 40 percent value given a planned Q4 2023 in service date, which was the assumption in the 2019 IRP.[7] Thus, the Company was motivated to move forward with the repowering effort at this site, which has remarkable wind energy characteristics, to secure the value of 100 percent PTCs for its customers. Delaying action would only have resulted in a less beneficial project for customers and would have resulted in customers continuing to pay higher costs for energy produced by the original turbines and under the existing, higher-cost wind energy lease structure for the facility.

Q. Mr. Hayet states that the Foote Creek I project provides only "very modest benefit."[8] Do you agree?

A. No. While Company witness Mr. Rick Link will address this in more detail in his rebuttal testimony, the economics of the Foote Creek I repowering project are very robust, with benefits of $48 million in the medium gas, medium CO_2 price policy scenario, upon which the Company's decision to move forward with the project was based. Even in the highly conservative low gas, CO_2 price policy scenario the project results in $6 million in benefits to customers.

Q. If the Company had delayed the repowering of Foote Creek I, as Mr. Hayet believes would have been more prudent, would customers have benefited?

A. No. As described in Company witness Mr. Rick Link's workpapers,[9] I understand the present value of the 100 percent PTCs associated with the Foote Creek I repowering project to be worth approximately $[redacted]. Thus, delaying the project such that

[7] *See* Action Item 2b, page 276, in PacifiCorp's 2019 Integrated Resource Plan, Volume I, October 18, 2019.
[8] *Id.* at line 526.
[9] *See* Proprietary Workpapers of Company Witness Rick Link, "FC1 and PM" folder, file "Table 3, Repower Foote Creek I 3_19 IRP 2019.07.11 13 WTG Clean Fig 2.xlsm", "Generic" tab, cell D1766.

it was considered later and qualified for only 40 percent of that PTC value would have reduced benefits to customers to approximately $[redacted]—a reduction in benefits of $[redacted]. This reduction in value would still have rendered the project economic for customers, but customers would have lost out on those additional PTC benefits.

Q. Mr. Hayet recommends that the Commission disallow the Company's request to recover the costs of the Foote Creek I repowering project.[10] Is Mr. Hayet's recommendation reasonable given his position that the project isn't sufficiently beneficial to customers?

A. No. Mr. Hayet recommends only that the costs of the Foote Creek I repowering project be excluded from the Company's revenue requirement, but he does not recommend the logical corollary to his position: that if the project was not prudent and its costs should not be recovered in rates then customers should therefore be held harmless by being returned to the status quo without the project. Were the Commission to adopt Mr. Hayet's recommendation, it would only be balanced for the Company's revenue requirement to be increased, rather than reduced, to cover the increased costs associated with continued operation of the original turbine equipment at the site without the cost savings and PTC benefits realized from the project. Such an adjustment would factor in costs related to the lower amount of generation available to serve customers from the original facility and its earlier co-ownership and power sales agreement structure. Because that result would actually harm customers by causing them to pay higher costs, the Commission should not adopt Mr. Hayet's recommendation.

[10] *Id.* at lines 689-690.

IV. CONCLUSION

Q. Please summarize your recommendations.

A. I recommend that the Commission allow the Company to recover its forecasted costs for the New Wind Projects and wind repowering projects, including the Foote Creek I project, as filed with its rebuttal testimony in rates. The Company has diligently and prudently managed the projects to ensure customers will receive the projects' benefits as cost-effectively and as soon as feasible in light of the unusual circumstances of a global pandemic.

Q. Does this conclude your rebuttal testimony?

A. Yes.

REDACTED
Rocky Mountain Power
Exhibit RMP___(TJH-1R)
Docket No. 20-035-04
Witness: Timothy J. Hemstreet

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Exhibit Accompanying Rebuttal Testimony of Timothy J. Hemstreet

Updated EV2020 Wind Capital Costs

October 2020

REDACTED

CONFIDENTIAL

New Wind Comparison to Pre-Approved Amounts

New Wind Project Capital Costs					
New Wind Project	**Online Date**	**Pre-Approved In-Service Capital Cost ($m)**	**Direct Capital Cost ($m)**	**Rebuttal Capital Cost ($m)**	**Direct Capital Cost Minus Rebuttal Capital Cost ($m)**
Cedar Springs II [1]	Dec-20	[redacted]			
Ekola Flats	Nov-20, Dec-20				
TB Flats	Nov-20, Dec-20, Jun-21				
New Wind Projects Total		**$1,189.2**	**$1,219.9**		**$16.3**

Notes:

[1] Costs as filed for Cedar Springs II include only Build Transfer Agreement costs and do not include internal project management costs of approximately $4.1 million or unused project contingency.

REDACTED
Rocky Mountain Power
Docket No. 20-035-04
Witness: Dana M. Ralston

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Rebuttal Testimony of Dana M. Ralston

October 2020

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Rocky Mountain Power ("Rocky Mountain Power" or the "Company").

A. My name is Dana M. Ralston. My business address is 1407 West North Temple, Suite 210, Salt Lake City, Utah 84116. My title is Senior Vice President of Thermal Generation and Mining.

I. QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I have a Bachelor of Science Degree in Electrical Engineering from South Dakota State University. I was previously the Vice President of Coal Generation and Mining from March 2015 to November 2017, and Vice President of Thermal Generation from January 2010 to March 2015. For 29 years before that, I held a number of positions of increasing responsibility within Berkshire Hathaway Energy's generation organizations, including the plant manager position at the Neal Energy Center. In my current role, I am responsible for operating and maintaining PacifiCorp's coal- and natural gas-fired generation fleet, coal fuel supply, and mining.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have filed testimony on behalf of the Company in proceedings before the Utah Public Service Commission ("Commission") and public utility commissions in California, Oregon, Washington, and Wyoming.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this case?

A. My testimony responds to the direct testimony of Office of Consumer Services ("OCS") witness Mr. Philip Hayet that recommends a disallowance of approximately

$1.13 million on a Utah-allocated basis, for costs related to two outages, one at Lake Side 2 Unit 3 and one at Blundell. My testimony demonstrates that the Company acted prudently with respect to the issues Mr. Hayet raises and the Commission should reject the proposed adjustments.

Lake Side 2 Unit 3 Outage (August 18, 2019)

Q. Please summarize the event that occurred at the Lake Side plant [redacted]

A. [redacted] The plant contacted the original equipment manufacturer ("OEM"), Siemens, to assist with the investigation, inspections, and disassembly.

Q. [redacted]

A. [redacted]

[redacted]. Due to the significance of the event, the Company hired and is working with a neutral third-party contractor to perform an additional RCA investigation in pursuit of a root cause. This report is expected to be completed by end of 2020.

Q. Was the required maintenance specified by the OEM performed on Lake Side 2 Unit 3 prior to this event?

A. Yes. The Company followed the OEM, Siemens, recommendations and required testing. Siemens was involved with and conducted the maintenance performed on the

[1] Direct Testimony of Philip Hayet at lines 260-261.
[2] Confidential OCS Exhibit 4.2D at 69 (Siemens Lake Side RCA Presentation p. 22).

unit. The Company was and continues to be actively engaged in managing the work as well as providing oversight. [redacted]

Q. [redacted]

A. [redacted]

Q. Mr. Hayet mentions a similar event that occurred in [redacted] What was learned from the similar event?

A. Siemens performed an RCA regarding the event in [redacted]. At the time of the first event, the Company had operated the unit within design, followed OEM recommendations, provided oversight and was engaged with Siemens during maintenance activities. [redacted] the Company hired a neutral third party expert to perform an additional RCA on the 2019 event in pursuit of a complete understanding of the failure.

[3] Confidential Exhibit RMP___(DMR-2R) at 9.

Q. When did Lake Side 2 Unit 3 return to service?

A. Lake Side 2 Unit 3 was returned to service on January 10, 2020.

Q. Was the entire Lake Side 2 plant unavailable during the Unit 3 generator failure?

A. No. After it was determined [redacted]

Q. Was PacifiCorp prudent in its operation of the Lake Side plant?

A. Yes. OCS inappropriately concludes [redacted]

Understanding the root cause is extremely important to the Company, and because of this, the Company hired a third-party contractor to perform an additional RCA investigation. The Company, however, has demonstrated that it has operated, maintained, and acted prudently with respect to Lake Side by: 1) operating the unit within design; 2) following OEM recommendations; 3) providing oversight and being

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[4] Direct Testimony of Philip Hayet at lines 266-268.

[5] Confidential OCS Exhibit 4.2D at 76 (Siemens Lake Side RCA Presentation p. 29 — "In conclusion the Root Cause Investigation did not identify a cause.").

engaged with Siemens during maintenance activities; 4) using the OEM experts on this equipment to perform maintenance; and 5) following FME policies and procedures for both the Company and the OEM. All of these actions demonstrate a concerted effort to ensure that the Company acted and continues to act prudently and in the best interest of customers. Mr. Hayet's position that the Company may be at fault is unsupported and should be rejected by the Commission because the Company was prudent in the operation, maintenance, and management of its Lake Side plant.

Blundell Unit 2 Outage (December 26, 2018)

Q. [redacted]

A. [redacted]

Q. [redacted]

A. [redacted]

Q. [redacted]

A. [redacted]

Q. [redacted]

A. [redacted]

[6] Confidential OCS Exhibit 4.2D at 11-12 (Veizades & Associates, Inc. RCA p. 6-7).

[redacted]

Q. [redacted]

A. [redacted]

Q. Has the Commission previously reviewed the Company's prudency regarding the December 26, 2018 Blundell Unit 2 outage?

A. Yes. The Commission reviewed the outage in the Company's 2019 energy balancing account, Docket No. 19-035-01. In that proceeding, the Commission found nothing that suggested the Company "overlooked or disregarded a specification requiring that the EPC contractor include validation and testing for the known types of breaker trip scenarios in the commissioning of Blundell Unit 2" and found no evidence that the commissioning plan was "flawed, contrary to industry practice, or that the testing for

[7] Direct Testimony of Philip Hayet at lines 363-367.
[8] Confidential OCS Exhibit 4.2D at 12 (Blundell Unit 2 Generator Root Cause p. 7).

the over-speed function failed to operate as expected."[9] As a result, the Commission determined that:

> RMP's actions concerning the construction, commissioning, and operation of the plant were prudent, that the event was unanticipated and unforeseeable, and that ultimate discovery of the event's root cause required an in-depth investigation by multiple third-party experts and was not unduly delayed. We conclude that the replacement power costs associated with the December 26, 2018 outage at Blundell Unit 2 were prudently incurred; therefore, no adjustment is warranted.[10]

Since this order was issued in March 2020, the OCS has not presented any additional facts that warrants a change to the Commission's ruling.

Q. What steps has the Company taken to ensure that a failure like this does not occur again?

A. [redacted]

Q. Did the Company act prudently?

A. Yes. The Company acted in a reasonable and responsible manner when constructing and commissioning Blundell Unit 2 in 2007 by involving experts that had significant knowledge and experience with the type of equipment installed. The Company acted

[9] *Application of Rocky Mountain Power to Increase the Deferred EBA Rate Through the Energy Balancing Account Mechanism,* Docket No. 19-035-01, Order Approving Rates and Granting Unopposed Motion to Vacate Orders at 9 (Mar. 4, 2020).
[10] Id.

prudently by hiring the known expertise of CEntry and Ormat to ensure logic functionality was thoroughly tested during the commissioning process. The Commission has acknowledged that the event was unanticipated and unforeseeable and OCS's position is unrealistic, unreasonable and requires the Company be held to a perfection standard.

Q. Does this conclude your rebuttal testimony?

A. Yes.

REDACTED
Rocky Mountain Power
Exhibit RMP___(DMR-1R)
Docket No. 20-035-04
Witness: Dana M. Ralston

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Exhibit Accompanying Rebuttal Testimony of Dana M. Ralston

Foreign Material Exclusion Inspection Report

October 2020

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Rocky Mountain Power
Exhibit RMP___(DMR-2R)
Docket No. 20-035-04
Witness: Dana M. Ralston

BEFORE THE PUBLIC SERVICE COMMISSION
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ROCKY MOUNTAIN POWER

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Exhibit Accompanying Rebuttal Testimony of Dana M. Ralston

Siemens – ST-20 Rotor-in FSP370

October 2020

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Rocky Mountain Power
Docket No. 20-035-04
Witness: Curtis B. Mansfield

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Rebuttal Testimony of Curtis B. Mansfield

October 2020

Q. Are you the same Curtis B. Mansfield that filed direct testimony on behalf of PacifiCorp d/b/a Rocky Mountain Power ("Rocky Mountain Power" or the "Company") in this proceeding?

A. Yes.

I. PURPOSE OF REBUTTAL TESTIMONY

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to provide an update on the Company's Wildland Fire Protection Plan ("Plan") since the Company's initial filing in this case and to respond to the Office of Consumer Services ("OCS") witness Ms. Donna Ramas' proposed adjustment to the Utah Advanced Meter Infrastructure ("AMI") Project.

II. WILDLAND FIRE PROTECTION PLAN

Q. Have there been updates to the costs in the revenue requirement in this case associated with the Plan since your direct testimony?

A. Yes. As stated in my direct testimony, at the time of filing the case in early May 2020, the Company was in the process of finalizing its Wildland Fire Protection Plan in preparation for the June 1, 2020 submission to the Public Service Commission of Utah ("Commission"). A copy of the final Plan is included with my testimony in this docket as Exhibit RMP___(CBM-1R).[1] At the time of filing this rebuttal testimony, the Commission has not issued an order approving the Plan; however, no party objected to the Commission approving the plan.[2] The Company is updating the revenue requirement in this case to reflect the final costs of the Plan.

[1] Rocky Mountain Power's Utah Wildland Fire Protection Plan, Docket No. 20-035-28 (June 1, 2020).
[2] The Office of Consumer Services conditioned their recommendation upon the Company meeting the statutory requirement of Utah Code Section 54-24-201(3)(c).

Q. What are the cost updates to the Plan?

A. As I explained in my direct testimony, the 2020 and 2021 Wildland Fire Mitigation costs are included in the rates requested by the Company in this proceeding. The updated costs in Table 1 below reflect the refined program costs filed in the Company's Utah Wildland Fire Protection Plan on June 1, 2020.

Table 1: Wildfire Mitigation Program Capital Costs

	2020 Capital Costs	**2021 Capital Costs**	**2022 Capital Costs**
Direct Filing Total Costs	$46,258,000	$49,857,500	$50,157,834
Utah Wildland Fire Protection Plan HB66 Costs	$37,381,417	$50,691,549	$50,134,094

The Plan costs were updated to reflect the availability of contract resources, material restrictions and permitting delays. Wildfire damage across the West, mainly California, limited the availability of contract resources. Additionally, internal and external construction resources assisted with storm damage repairs, including providing mutual aid to impacted areas outside of Utah. Material availability has been impacted by an increase in wildfire projects in the Western States as well as reductions in product availability due to manufacturing facilities being suspended or shut down by COVID-19. With wildfires still active in California, Oregon and Washington, the Company anticipates there may be additional delays in the planned work for 2020 resulting in an additional reduction of close to $12 million, which would require the plan to be rephased through 2026. Mr. Steven R. McDougal provides the details of how the updated rebuttal costs have been included in the requested revenue requirement.

III. AMI PROJECT

Q. What does the OCS propose with respect to the AMI project?

A. OCS witness Ms. Ramas recommends the AMI project be completely removed from the test period revenue requirement in this case because the project has been delayed and is now anticipated to be completed after the end of the test period.

Q. Ms. Ramas, based on responses to data requests, anticipates only $12 million of the Utah AMI project to be placed into service on an average test year basis. Do you agree that this warrants a complete removal of the project from the test period?

A. No. As explained in the response to OCS data request 5.16, the Company expects the AMI project to be completed by the end of 2022. In response to OCS data request 11.1(b), the Company noted the *completion* of the project was delayed until the end of 2022 due to cybersecurity concerns, vendor-recommended technology changes and COVID-19. However, as shown in the workbook attached to the response to OCS data request 11.1 and included here as Exhibit RMP___(CBM-2R), the Company expects to place approximately $46.8 million into service in the test period. While it is true that the entire AMI project will not be completed until 2022, the entire project does not need to be complete before the assets placed into service are used and useful in providing some of the benefits that I outlined in my direct testimony. The field network will be substantially complete by the end of 2021 and the system will begin reading the existing automatic meter reading meters soon after. Ms. Ramas gives no good reason not to allow the Company to update to the current forecast instead of simply removing the entire project from the case. The Company has updated the revenue requirement requested in this case to reflect the current forecast, which is a reduction to the revenue requirement as discussed by Mr. McDougal.

Q. Ms. Ramas points out that in the response to OCS data request 11.2, the Company stated that the eight benefits identified in my direct testimony are anticipated to begin in January 2023. Please clarify.

A. The eight benefits I listed in my direct testimony are:

1. Provide customers access to data regarding their hourly energy consumption, which will enable them to make more informed energy decisions;
2. Provide better customer service by giving the Company's customer service representatives information necessary to provide accurate responses to customer inquiries and facilitate customer complaint resolution;
3. Reduce the number of estimated bills by providing the Company with actual meter data regardless of physical access barriers, bad weather delays, or other factors that can impede physical meter reading and give rise to estimated billing;
4. Perform remote connect and disconnect at sites with smart meters that will enable service to be turned on and off on a near real-time basis without deploying employees to customers' premises;
5. Detect, react, and troubleshoot power outages in a more timely manner, without the need to wait for an outage notification directly from the customer;
6. Obtain analytic information at sites with smart meters, such as temperature, voltage, and power quality data, which can be used to assess system performance and improve service to customers;

7. Introduce efficiencies related to automation that reduce the cost to obtain meter reads and perform service connects and disconnects; and
8. Enhance safety and reduce carbon dioxide emissions through the reduction of vehicles used for drive-by meter reading operations.

While it is true that completion of the project will allow all of the benefits to be deployed, it is also true that customers will experience many of these benefits before completion. For example, the first three benefits stated above are scheduled to be available to residential customers with new AMI meters by the end of 2021 when the Gen5 field network is completed in their neighborhoods. As stated in the response to OCS data request 11.2c, full AMI data availability, required for the remaining benefits, is anticipated to begin in January 2023 after all AMI meters have been installed.

Q. Did the OCS raise other issues with the AMI project in its testimony in the cost of service and pricing phase of this case?

A. Yes. In addition to the arguments raised by Ms. Ramas on behalf of the OCS in the revenue requirement phase of this case, OCS witness Mr. Ron Nelson presents additional recommendations and arguments with respect to the AMI project in his direct testimony that was filed in the cost of service and pricing phase on September 15, 2020. It is unclear to the Company why the OCS decided to split its arguments against the Company's AMI project between two phases of testimony; however, for consistency I will address these additional issues in my rebuttal testimony in the cost of service and pricing phase of this proceeding.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Rocky Mountain Power
Exhibit RMP___(CBM-1R)
Docket No. 20-035-04
Witness: Curtis B. Mansfield

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Curtis B. Mansfield

RMP Utah Wildland Fire Protection Plan

October 2020

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W North Temple, Suite 330
Salt Lake City, Utah 84114

June 1, 2020

VIA ELECTRONIC FILING

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84114

Attention: Gary Widerburg
Commission Administrator

RE: Docket No. 20-035-28
Rocky Mountain Power's Utah Wildland Fire Protection Plan

Pursuant to Utah Code § 54-24-201(3), PacifiCorp, d.b.a. Rocky Mountain Power, ("the Company") hereby submits its comprehensive wildland fire projection plan.

The Company respectfully requests that all formal correspondence and requests for additional information regarding this filing be addressed to the following:

By E-mail (preferred): datarequest@pacificorp.com
utahdockets@pacificorp.com
jana.saba@pacificorp.com
tim.clark@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232

Informal inquiries may be directed to Jana Saba at (801) 220-2823.

Sincerely,

Joelle Steward
Vice President, Regulation

Enclosures

Utah Wildland Fire Protection Plan

June 1, 2020

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Tables

Definition of Common Acronyms

ANSI	American Nation Standards Institute
APLIC	Avian Power Line Interaction Committee
APP	Avian Protection Plan
BLM	Bureau of Land Management
BMP	Best Management Practices
CONDFRAY	Conductor Frayed or Damaged
EEI	Edison Electric Institute
ELMFIRE	Eulerian Level Set Model for Fire Spread
EOC	Emergency Operations Center
ESF	Emergency Support Functions
FFSL	Utah Division of Forestry, Fire and State Lands
FFWI	Fosberg Fire Weather Index
FHCA	Fire High Consequence Area
FPI	Facility Point Inspection
GIS	Geographic Information System
GUYMARK	Missing or broken guy marker
ICP	Incident Command Post
ICS	Incident Command System
IVM	Integrated Vegetation Management
JIS	Joint Information System
kV	Kilovolt
MBTA	Migratory Bird Treaty Act
MVCD	Minimum Vegetation Clearance Distance
NARR	North American Regional Reanalysis
NESC	National Electric Safety Code
NGO	Nongovernmental organization
NIMS	National Incident Management System
O&M	Operations & Maintenance
OH	Overhead
PSPS	Public Safety Power Shutoff
T&D	Transmission and Distribution
USFS	United States Forest Service
USFWS	United States Fish and Wildlife Service
WITS	Wildlife Incident Tracking System
WPP	Wildlife Protection Plan
WRF	Weather Research and Forecasting
WRI	Watershed Restoration Initiative
ZOP	Zone of Protection

Introduction and Cost Summary

Rocky Mountain Power is submitting this wildland fire protection plan under UTAH CODE § 54-24-201. Due to the growing threat of catastrophic wildfire in the western United States, Rocky Mountain Power has developed a comprehensive plan for wildfire mitigation efforts in all of its service territories. This plan specifically guides the mitigation strategies that will be deployed in Utah. These efforts are designed to reduce the probability of utility related wildfires, as well as to mitigate the damage to Rocky Mountain Power facilities because of wildfire.

Wildfire has long been an issue of notable public concern. Due to the potential for fire caused by sparks emitted from electrical facilities, wildfire mitigation is of particular concern for electric utilities. Trends in the growth of wildfire size and intensity have magnified these concerns. Despite efforts of fire suppression agencies and increased suppression budgets, wildfires have continued to grow in number, size and intensity. Increased human development in the wildland-urban interface, the area where people (and their structures) are intermixed with, or located near, substantial wildland vegetation, has exacerbated the costs of wildfire damage in terms of both harm to people and property damage. A wildfire in an undeveloped area can have ecological consequences – some positive, some negative – but a wildfire in an undeveloped area will not, generally, directly affect large numbers of people. A wildfire engulfing a developed area, on the other hand, has catastrophic consequences on people and property.

The relationship between wildfire and public utilities has been brought to the forefront by recent developments in California, resulting in substantial loss of human life and property damage.[1] Although Utah does not have the same degree of wildfire risk as some other places (such as California due, among other factors, to its unique Santa Ana winds), the wildfire risk in Utah is still substantial. The general trend toward larger and more destructive fires is not unique to California. In 2018, for example, multiple western states had wildfires exceeding 100,000 acres, including Oregon (Klondike Fire and Boxcar Fire), Nevada (Martin Fire and Sugarloaf Fire), and Utah (Pole Creek Fire).

The state of Utah has recognized and emphasized the risk of wildfire for many years. For example, following the difficult 2012 wildfire season, the state of Utah responded with the publication of the Catastrophic Wildfire Reduction Strategy, which recognizes the long-term trend toward larger and more destructive wildfires. Since 2012, Utah has witnessed a growing risk of wildfire. Utah experienced one of its worst, if not very worst, wildfire seasons in 2018, including the Trail Mountain Fire, the Dollar Ridge Fire, and the Pole Creek Fire. Due to a particularly wet year in 2019, with precipitation well spread through the warmer months, Utah had a relatively low wildfire impact year in 2019. A low-impact year, however, can add to the fuel inventory and increase the risk during subsequent seasons. Vigilance will be warranted in

[1] The October 2017 "firestorm" in northern California; the December 2017 Thomas Fire north of Los Angeles, California; the July 2018 Carr Fire near Redding, California; and the November 2018 Camp Fire, which decimated the city of Paradise, California.

2020 and beyond. Accordingly, Rocky Mountain Power is committed to making long-term investments to reduce the chances of catastrophic wildfire.

The preventative measures described in this wildland fire protection plan include proactive investments to construct, maintain and operate electrical lines and equipment in a manner that minimizes the risk of catastrophic wildfire. In evaluating which engineering, construction and operational strategies to deploy, Rocky Mountain Power was guided by the following core principles:

- Frequency of ignition events related to electric facilities can be reduced by engineering more resilient systems that experience fewer fault events.
- When a fault event does occur, the impact of the event can be minimized using equipment and personnel to isolate the fault event.
- Systems that facilitate situational awareness and operational readiness are central to mitigating fire risk and its impacts.
- A successful plan must also consider the impact on Utah customers and Utah communities, in the overall objective to provide reliable, safe and affordable electric service.

The strategies embodied in this plan are evolving and are subject to change. As new analyses, technologies, practices, network changes, environmental influences or risks are identified, modifications may be incorporated into future iterations of the plan, as contemplated in UTAH CODE § § 54-24-201(3)(a)(ii).

Plan Cost Summary

The following tables present a summary of the planned mitigation activities, the total estimated costs and the planned timeframe for implementation.

Table 1. Rocky Mountain Power's Utah Wildland Fire Protection Implementation Summary – Capital

Incremental Capital in $ millions Mitigation Program	2020	2021	2022	2023	2024	2025	2026	Total
Advanced Protection and Control	$ 3,253,786	$ 3,003,944	$ 2,255,000	$ 955,000	$ 265,000	$ 265,000	$ 265,000	**$ 10,262,730**
Environmental	$ 241,728	$ 232,128	$ 232,128	$ 232,128	$ 232,128	$ 232,128	$ 232,128	**$ 1,634,496**
Inspect and Correct	$ 1,000,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	**$ 10,000,000**
Operational Practices	$ 2,882,769	$ 1,013,750						**$ 3,896,519**
Situational Awareness	$ 445,000	$ 240,000	$ 150,000	$ 112,000			$ 112,000	**$ 1,059,000**
System Hardening	$ 29,558,134	$ 44,701,727	$ 45,996,966	$ 37,651,673	$ 25,749,652	$ 20,009,524	$ 10,029,690	**$ 213,697,366**
Total	**$ 37,381,417**	**$ 50,691,549**	**$ 50,134,094**	**$ 40,450,801**	**$ 27,746,780**	**$ 22,006,652**	**$ 12,138,818**	**$ 240,550,111**

Table 2. Rocky Mountain Power's Utah Wildland Fire Protection Implementation Summary – O&M

Incremental O&M in $ millions Mitigation Program	2020	2021	2022	2023	2024	2025	2026	Total
Vegetation Inspections, Mitigation, Pole Clearing – Distribution	$ 1.5	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	**$ 9.1**
Vegetation Inspections, Mitigation, Pole Clearing – Transmission	$ 0.3	$ 0.3	$ 0.3	$ 0.3	$ 0.3	$ 0.3	$ 0.3	**$ 1.8**
FHCA Inspections	$ 0.8	$ 0.9	$ 0.9	$ 0.9	$ 1.0	$ 0.9	$ 0.9	**$ 6.3**
Condition Corrections – Distribution	$ 1.1	$ 1.1	$ 1.1	$ 1.1	$ 1.1	$ 1.1	$ 1.1	**$ 7.7**
Condition Corrections – Transmission	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	**$ 0.5**
Weather Station Maintenance, Tool Development, Community Meetings, Advertising – Other	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 0.2	**$ 1.3**
Fault Anticipator - Other	$ -	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	**$ 0.6**
Environmental – Wildlife Protection Program, Habitat Enhancements, Other – Distribution	$ 0.1	$ 0.4	$ 0.4	$ 0.4	$ 0.4	$ 0.4	$ 0.4	**$ 2.5**
Environmental – Wildlife Protection Program, Habitat Enhancements, Other – Transmission	$ 0.0	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	**$ 0.4**
Patrolling Costs, Field Response (PSPS) – Other	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 0.2	**$ 1.4**
Alert Wildfire Cameras – Other	$ 0.1	$ 0.3	$ 0.3	$ 0.2	$ 0.3	$ 0.3	$ 0.2	**$ 1.5**
Wood Pole Wrap	$ -	$ 0.1	$ -	$ -	$ -	$ -	$ -	**$ 0.1**
Total	**$ 4.3**	**$ 5.0**	**$ 4.8**	**$ 4.8**	**$ 4.9**	**$ 4.8**	**$ 4.7**	**$ 33.2**

1. Risk Analysis and Drivers

1.1. Methodology for Identifying and Evaluating Risk

This risk evaluation process employs the concept that the risk is essentially the product of the likelihood of a specific risk event times the impact of the event. The likelihood, or probability, of an event is an estimate of a particular event occurring within a given time frame. The impact of the event is an estimate of the effect when an event occurs. Impact can be evaluated using a variety of factors, including considerations centered on health and safety, the environment, customer satisfaction, system reliability, and financial implications. As discussed below, the risk analysis in this plan focuses on the potential impact in harm to people and damage to property.

1.1.1. Modeling Rocky Mountain Power's Wildfire Risk

A disruption of normal operations on the electrical network, called a "fault" in the industry, could be a possible ignition source for wildfire. Under certain weather conditions and in the vicinity of wildland fuels, an ignition can grow into a harmful wildfire, potentially even growing into a catastrophic fire causing great harm to people and property. This general relationship is shown in the Venn diagram below.

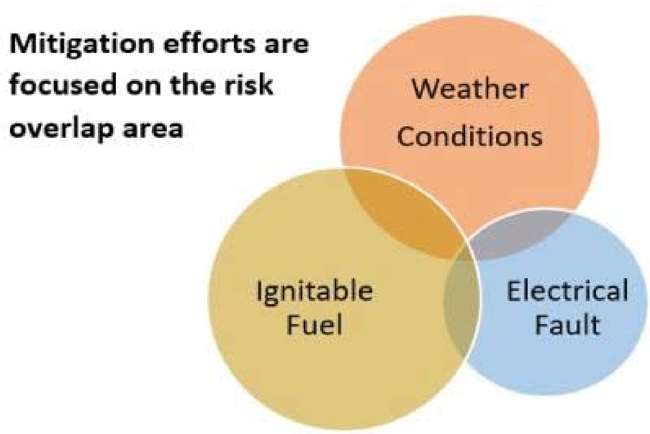

Figure 1. Utility Fire Risk Conceptual Model

Rocky Mountain Power's risk analysis first concentrates on weather conditions and ignitable fuels, to identify the geographic areas in Rocky Mountain Power's service territory at the greatest risk of catastrophic fire. The analysis also explores Utah's fire history, its recorded causes, the acreage impact of the fires, and the seasonality of fires. The analysis further considers historical outage data, reflecting the best available data regarding the potential for faults on the electrical system.

Rocky Mountain Power's analysis of the wildfire risk in Utah took advantage of a larger PacifiCorp effort across all of its service territory states.[2] In 2018 and 2019, PacifiCorp completed a wildfire risk analysis for Utah, Idaho, Wyoming, Oregon, and Washington. This effort was patterned after the methodology developed after a long and iterative process in California, in which PacifiCorp participated because of its California service territory. To take advantage of that experience, PacifiCorp engaged fire-science engineering firm REAX Engineering Inc. to identify areas of elevated wildfire risk, which were ultimately designated with the name of Fire High Consequence Areas (FHCA).

PacifiCorp and REAX first identified the general geographic areas subject to the risk analysis, which included all of PacifiCorp's service territory and a 25-mile radius study area around all PacifiCorp-owned transmission lines, as shown below:

Topography (elevation, slope, aspect) segmented into 2-km-square cells:

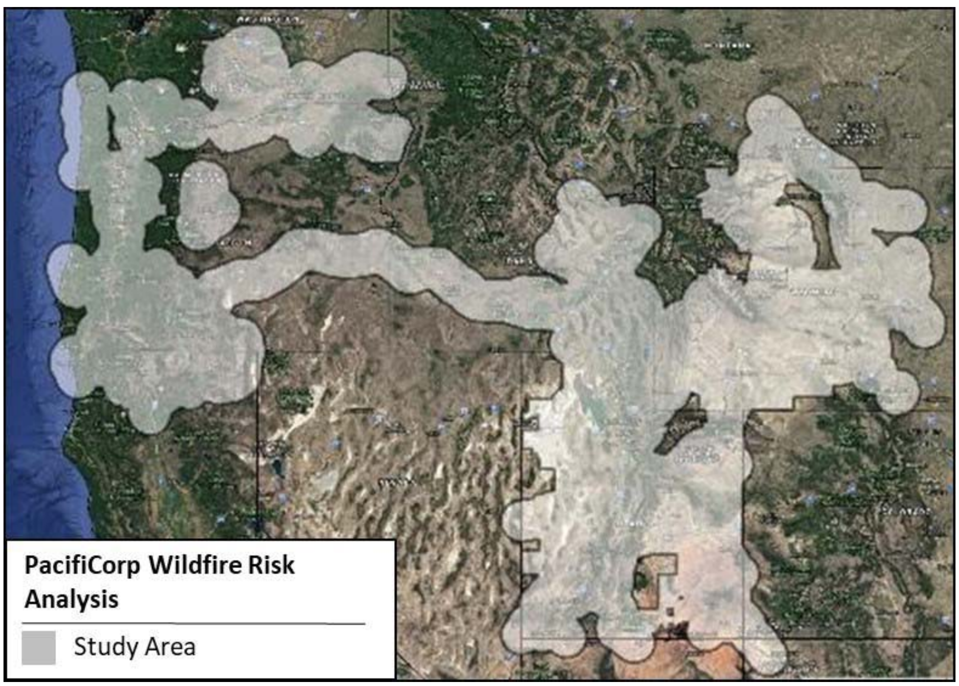

Figure 2. Study Area for Fire Risk Mapping Project

[2] Rocky Mountain Power is the division of PacifiCorp that has service territory in Utah, Idaho, and Wyoming, Pacific Power is the division of PacifiCorp that has service territory in California, Oregon, and Washington.

REAX then conducted a wildfire risk analysis on this area. REAX used the following data and processes:

1. Topography of the land, including elevation, slope and aspect
2. Fuel data (from a dataset known as LANDFIRE[3]) with 30 m pixel resolution, calibrated against one of 40 "fuel models[4]," which quantify fuel loading, fuel particle size and other quantities needed by fire models to calculate rate of spread
3. Weather Research and Forecasting (WRF), resulting in climatology derivative from North American Regional Reanalysis (NARR) with resolution at 32 km, which is a hybrid of weather modeling and surface weather observations (including temperature, relative humidity, wind speed/direction, and precipitation, weather balloon observations of wind speed/direction and atmospheric, sea surface temperatures from buoys, satellite imagery for cloud cover and precipitation).[5]
4. Historical fire weather days spanning the period from January 1, 1979 through December 31, 2017, determined by calculating the Fosberg Fire Weather Index, modified to recognize off-season moisture, as measured by Schroeder's ember ignition probability P_{ign}.[6]
5. Estimated live fuel moisture
6. Ignition modeling, using Monte Carlo-simulated ignition scenarios
7. Fire spread modeling, Eulerian Level Set Model for Fire Spread (ELMFIRE), which is software for modeling wildland fire spread; ELMFIRE is used to run Monte Carlo-simulated burn scenarios that incorporate impacts to populations (by using the proxy of structures involved in any burn scenario, based on census tract data[7]), climatology, using spread algorithms developed in Eulerian Level Set Model for Fire Spread (ELMFIRE), conducted over a six-hour burn period, where fire type (surface, passive crown or active crown fire) in combination with flame length is critical to quantify output metrics including fire size (acres), fire volume (acre-ft) and the number of structures within the fire perimeter.

Through this process, individual blocks of geographic area, each 2 kilometer square, received a grid score corresponding to its relative wildfire risk. To establish the Fire High Consequence Area (FHCA), REAX used the prior California mapping project for calibration and assigned cell scores correlating with California statewide cell scores. This approach enabled an "apples-to-apples"

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[3] https://www.landfire.gov/datatool.php
[4] https://www.landfire.gov/fbfm40.php
[5] Essentially, a weather model similar to WRF assimilates/ingests several thousand weather observations over a three-hour period and then uses that information to create a 3D representation of the atmosphere every three hours. This includes not only surface (meaning near ground level) quantities but also upper atmosphere quantities as well. The NARR dataset is available from 1979 (when modern satellites first became available) to current day (with a lag of a few weeks).
[6] This metric MFFWI, was calculated in three-hour intervals for the time period of 1979–2017, and averaged over a six-hour period, since the early hours of a large fire are significant predictors for most catastrophic fires. The largest values were extracted, which involved about 200 days of hourly climatology inputs.
[7] http://www2.census.gov/geo/tiger/TIGER2010/TABBLOCK/2010/tl_2010_06_tabblock10.zip, ftp://ftp2.census.gov/geo/tiger/TIGER2010BLKPOPHU/tabblock2010_06_pophu.zip

comparison to the results of that prior project, so that the relative degree of wildfire risk in areas of other states could be compared to the risk in areas of California. REAX then used geographic information system (GIS) software algorithm "Jenks natural breaks" to segment areas into 33 families of risk areas[8], so that all cell areas were given a score from 0 to 32, as shown in Figure 3. Cell values do not imply direct mathematical relationships, but rather indicate bins of relative catastrophic wildfire risk, when population density is factored into the weighting process.

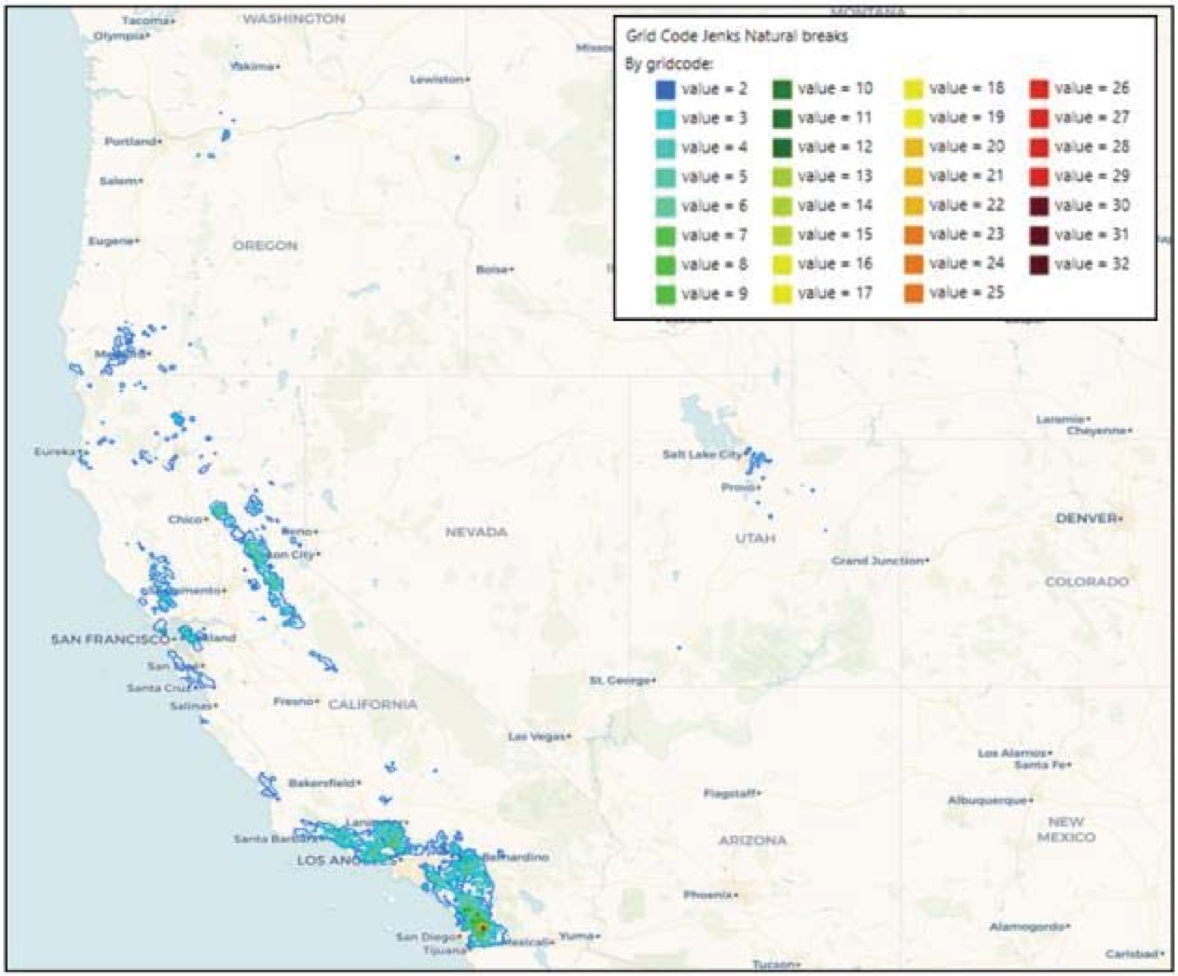

Figure 3. Grid Code of Jenks Natural Breaks

After REAX completed the computer modeling, a "ground-truthing" activity was completed by evaluating historical fire perimeters, existing Rocky Mountain Power facility equipment, and local conditions. The ground-truthing exercise generally validated the modelling performed by REAX and resulted in some relatively minor adjustments to the preliminary boundaries. Rocky

[8]https://www.spatialanalysisonline.com/extractv6.pdf

Mountain Power plans to make an annual review of the FHCA boundaries and may make adjustments, based on updated modeling, integration of other risk assessment tools, and knowledge of local conditions.

The resulting Utah FHCA, together with magnified views on certain FHCA areas, is shown in the following figures.

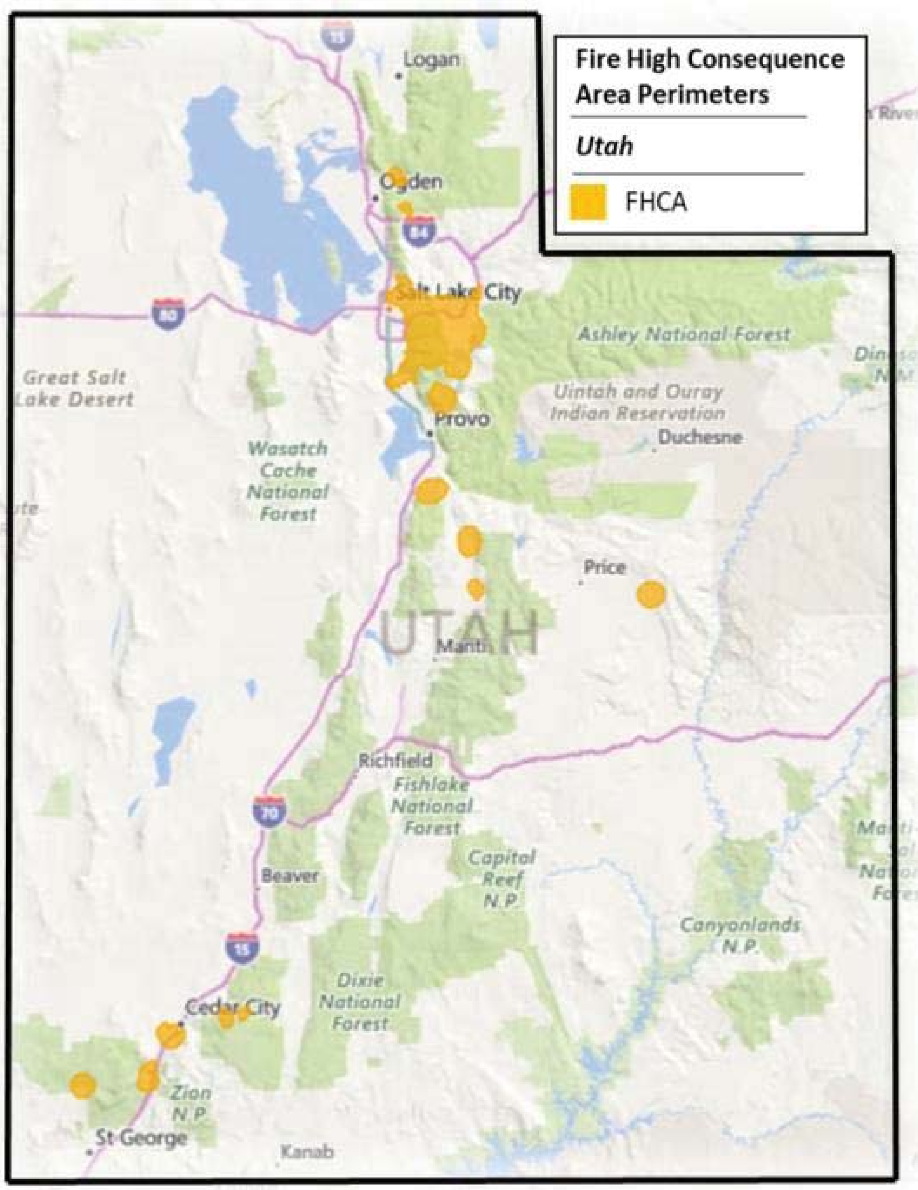

Figure 4. Utah Statewide FHCA Perimeters

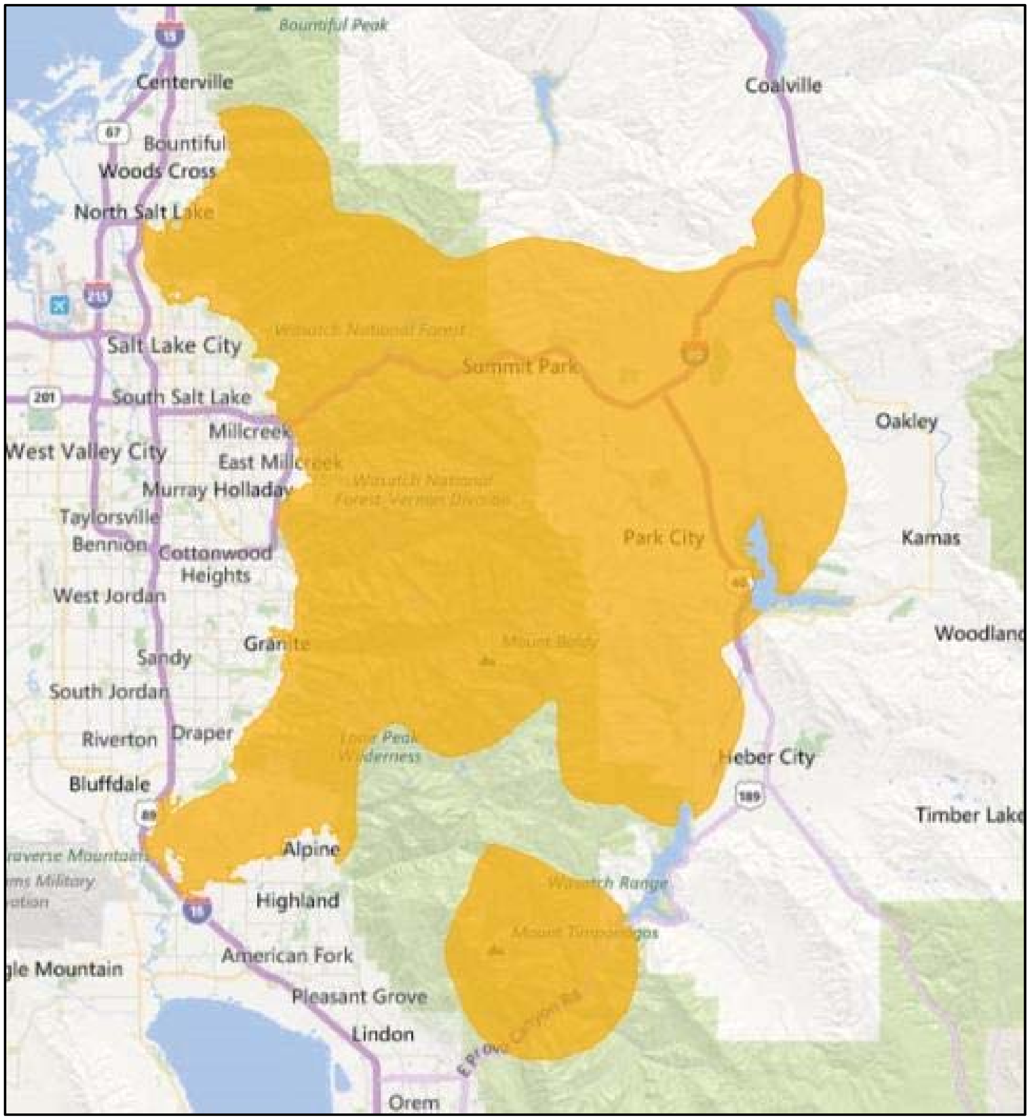

Figure 5. Salt Lake City Metro FHCA Perimeters

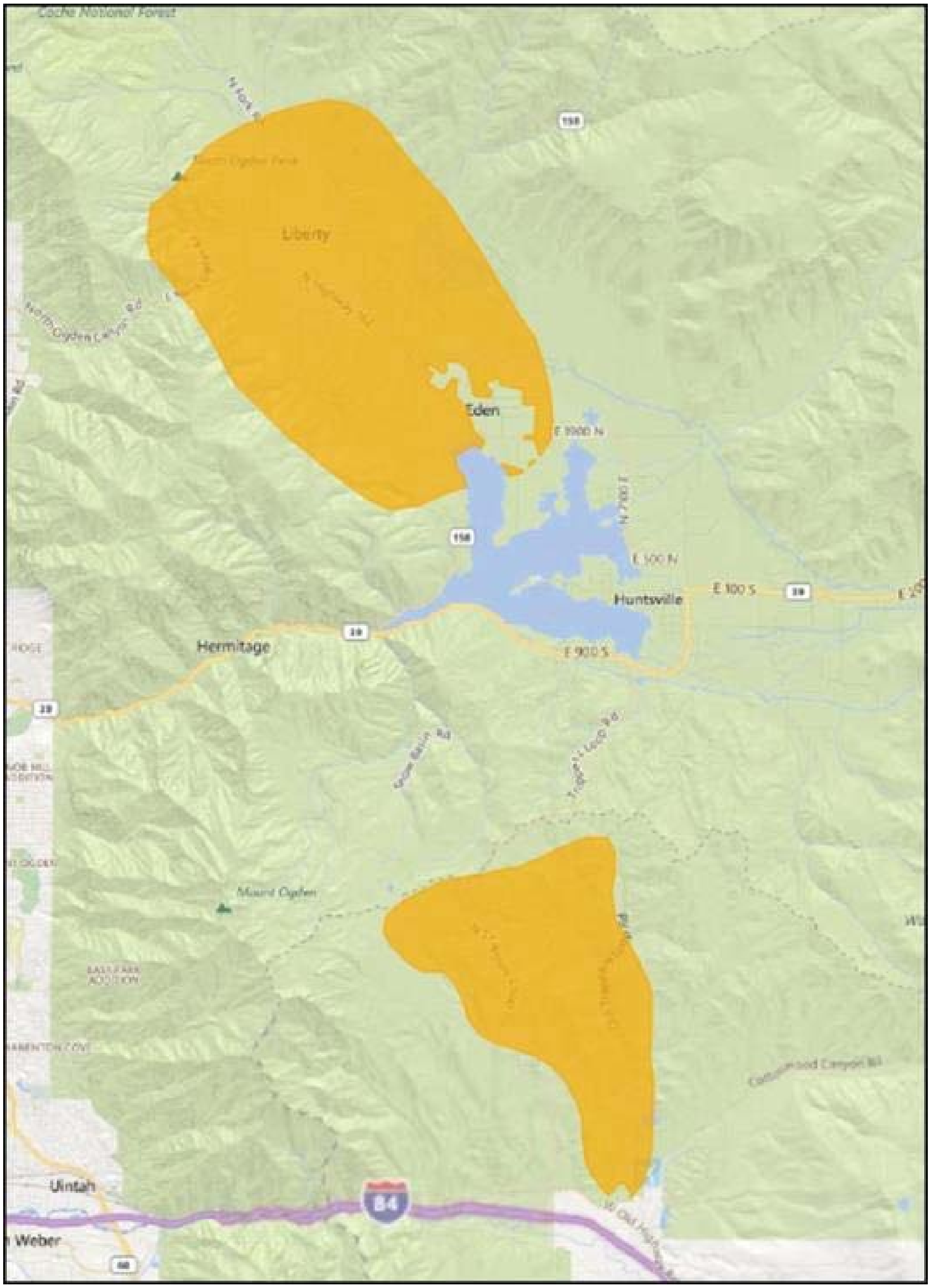

Figure 6. Weber and Morgan Counties FHCA Perimeters

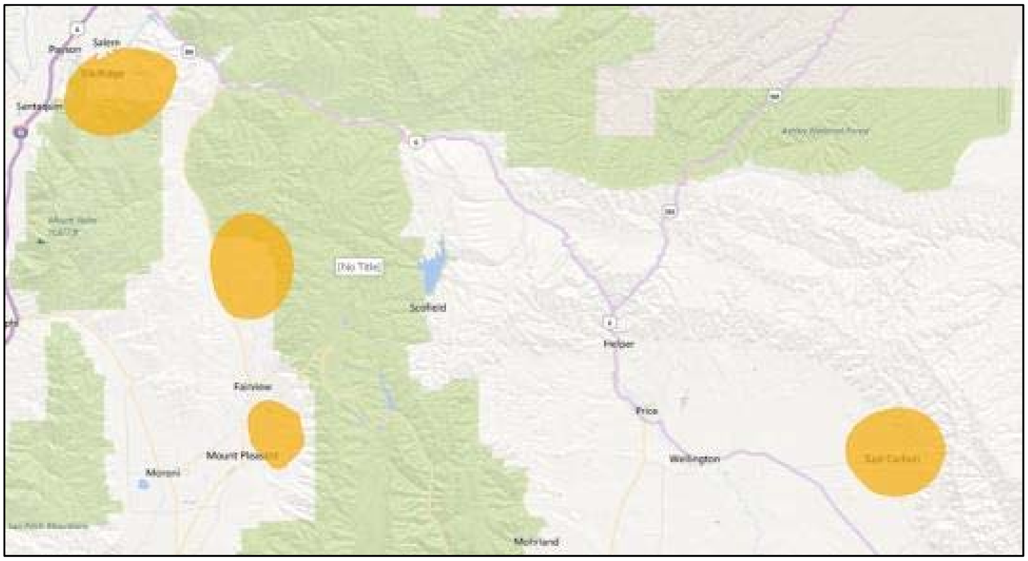

Figure 7. Carbon, Sanpete and Utah Counties FHCA Perimeters

Figure 8. Washington, Iron and Garfield Counties FHCA Perimeters

1.2. Asset Inventory in the FHCA

In Utah, Rocky Mountain Power provides electricity to over 950,000 customers via over 500 substations and 18,000 miles of overhead transmission and distribution lines, across a service territory encompassing nearly 58,900 square miles. The three primary categories of assets subject to wildfire mitigation treatment are described as follows:

Table 3. Primary Asset Categories

Asset Classification	Asset Description
Transmission Line Assets	Include conductor, transmission structures, and switches operating at a higher level voltage (typically, any line operating at or above 46 kV is a transmission line).
Distribution Line Assets	Include overhead conductor, underground cabling, transformers, voltage regulators, capacitors, switches, line protective devices, operating at a lower voltage (again, typically less than 46 kV).
Substation Assets	Include major equipment such as power transformers, voltage regulators, capacitors, reactors, protective devices, relays, open-air structures, switchgear and control houses.

Many wildfire mitigation strategies are focused on assets located in the FHCA. PacifiCorp has 489 miles of distribution line, 210 miles of transmission line and 26 substations located in the FHCA. The following table includes the breakdown of Rocky Mountain Power's Utah assets in the FHCA.

Table 4. Breakdown of Utah Assets in the FHCA

Asset	Total	FHCA	
	Line-Miles	Line-Miles	%
OH Transmission	7077	210	3.0%
46 kV Transmission Lines	2075	79	3.8%
69 kV Transmission Lines	549	17	3.0%
138 kV Transmission Lines	1969	90	4.6%
230 kV Transmission Lines	564	11	2.0%
345 kV Transmission Lines	1918	14	0.7%
OH Distribution	10937	489	4.5%
OH Lines - Miles	18014	699	3.9%
Substations	503	26	5%

1.3. State-Specific Fire History and Causes

To further develop an understanding of wildfire risks in both the state and company service territory, Rocky Mountain Power analyzed Utah fire history and ignition sources from 2008 through 2019, using data from the Utah Division of Forestry, Fire and State Lands (FFSL). Ignition sources, both by number of ignitions in a given category, and by the amount of acres burned by ignitions in a particular category, are shown in the figures below. Whether assessed by the number of ignitions or by the acres burned from a particular cause, lightening was the leading cause of wildfire in Utah over the prior decade. The miscellaneous category next is the next largest category. The miscellaneous category includes ignition causes attributed to power lines, fireworks, firearms and others.

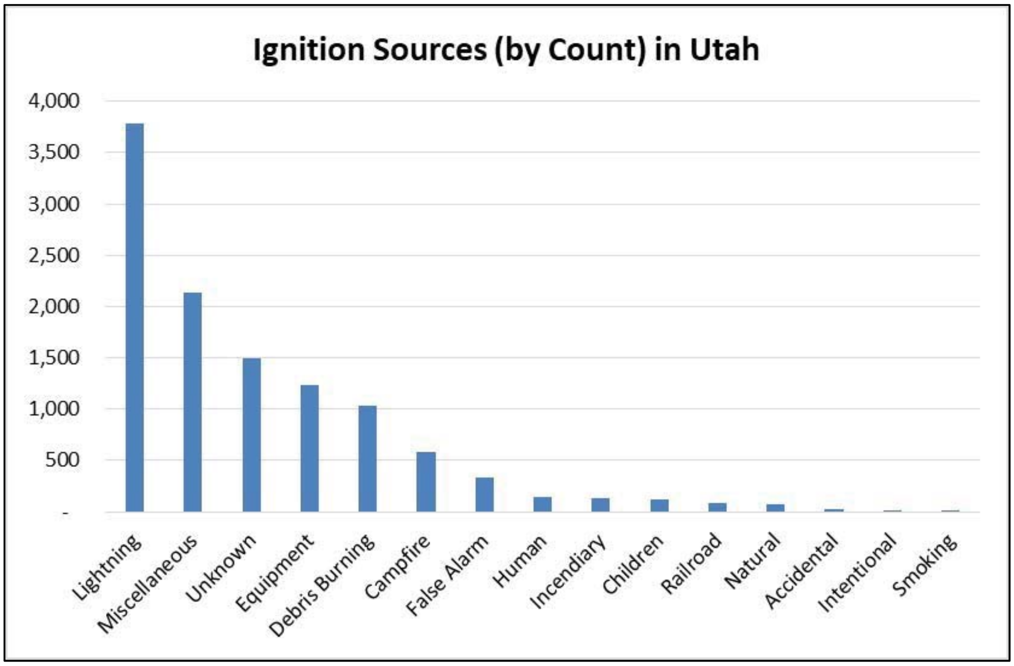

Figure 9. Fire History Ignition Source in Utah

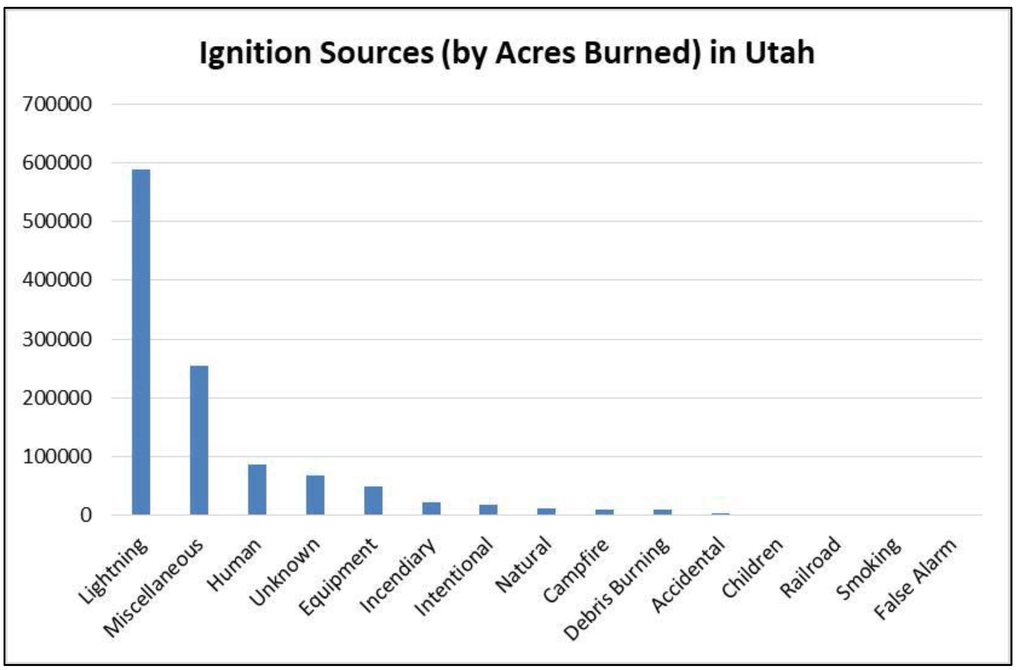

Figure 10. Fire History Total Acres Burned in Utah

The same data, expressed as a percentage of the total in a pie chart format, is shown in the figures below. The equipment category accounts for approximately 19% of the number of ignitions and 23% of ignitions by acres burned.

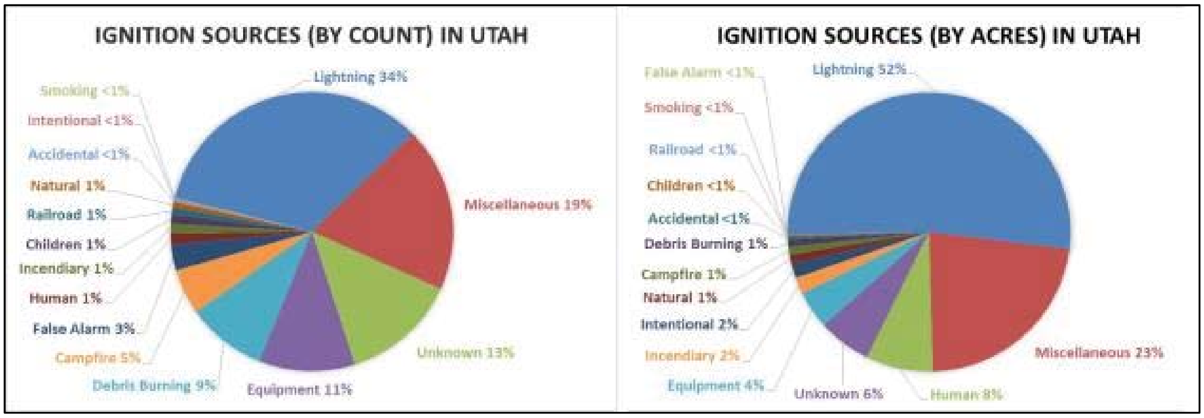

Figure 11. 2008–2019 Fire History Ignition Sources by Count and by Acres for the State of Utah; Percentages of Total Incidents

1.3.1. Determining Historical Fire Season

Rocky Mountain Power plotted the cumulative acres burned against the day of the year for the 12-year period from 2008 to 2019. While it does not mean that a wildfire cannot occur outside of fire season, the following figure supports the general conclusion that June 1 through October 1 is a good representation for when fire risk is elevated for the state as a whole.

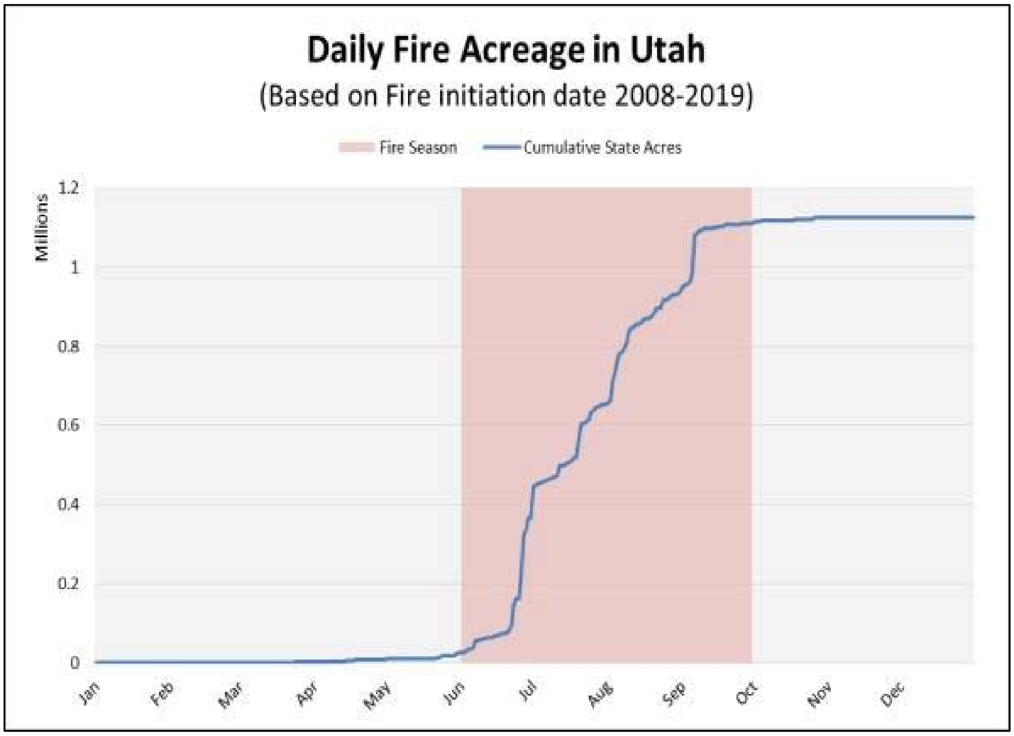

Figure 12. 2008–2019 Cumulative Acres Burned by Day of the Year in Utah.

1.4. Assessment of Electric Utility-Related Fire Ignition Risk

Outage data is the best available data to correlate an identifiable event on the electrical network to the risk of a utility-related wildfire. There is a logical physical relationship, when a fault creates a spark, there is a risk of fire. An outage – which is when a line is unintentionally de-energized – is most often rooted in a fault. Accordingly, the company has closely analyzed the causes and frequency of outages. This analysis is geared to determine which mitigation strategies are best suited to minimize fault events, thereby reducing the risk of fire.

1.4.1. General Outage Categories

Rocky Mountain Power maintains outage records in the normal course of business, as part of Rocky Mountain Power's historical efforts to assess service reliability. These records document the frequency, duration and cause of outages. For purposes of this wildfire risk assessment, the company has created nine categories of outage events, with each category related to a type of wildfire risk. Those categories are listed in the following table:

Table 5. Rocky Mountain Power's Outage Categories

Outage Categories
Contact From Object
Contamination
Equipment Failure
Normal Operation
Other
Unknown
Vandalism/Theft
Contact From Third Party

Using the historical distribution outage data, for the years 2015 to 2019, each individual outage was assigned to one of the outage categories listed above. The results of such categorization are shown in the following tables:

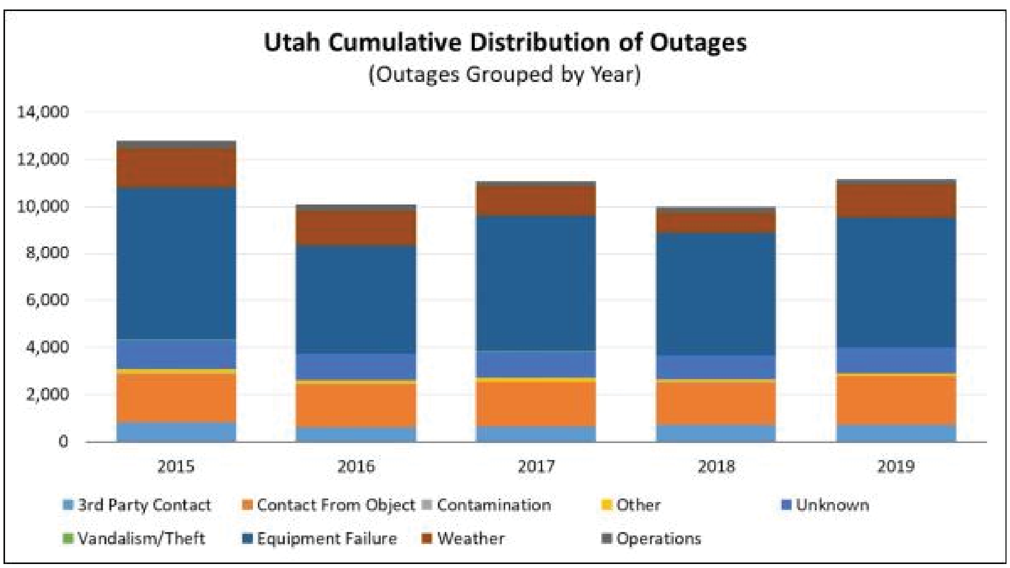

Figure 13. Cumulative Distribution of Outage Category Grouped by Year

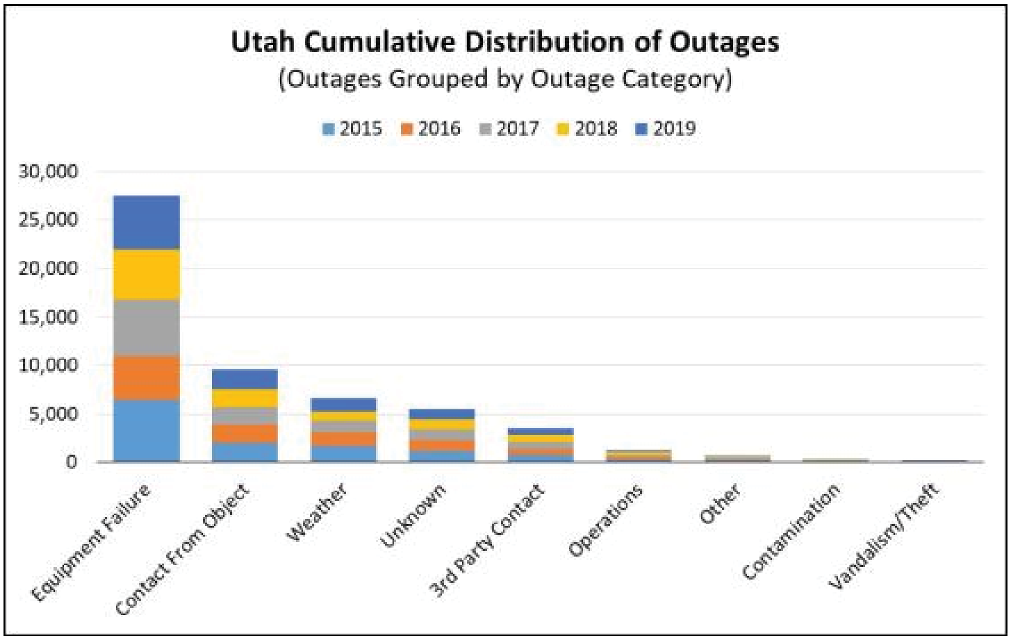

Figure 14. Cumulative Distribution of Outage Category Grouped by Outage Category

1.4.2. Specific Outage Subcategories

To further develop this analysis, the company broke two categories into subcategories. Because of their numerical significance and because of their potential correlation with sparks, the general categories for “Contact From Object” and “Equipment Failure” were subdivided into the following groups:

Table 6. Outage Subcategories for Object Contact and Equipment Failure

Contact From Object	Animal contact
	Other (e.g., balloons)
	Vegetation contact
Equipment Failure	Conductor
	Crossarm
	Cutout
	Insulator
	Lightning arrester
	Other
	Pole
	Sectionalizer
	Splice/clamp/connector
	Switch
	Transformer
	Voltage regulator

Again using the historical outage data, for the same years, each individual outage in the contact from object and equipment failure general categories was assigned to one of the subgroups listed above. The results are shown in the following table:

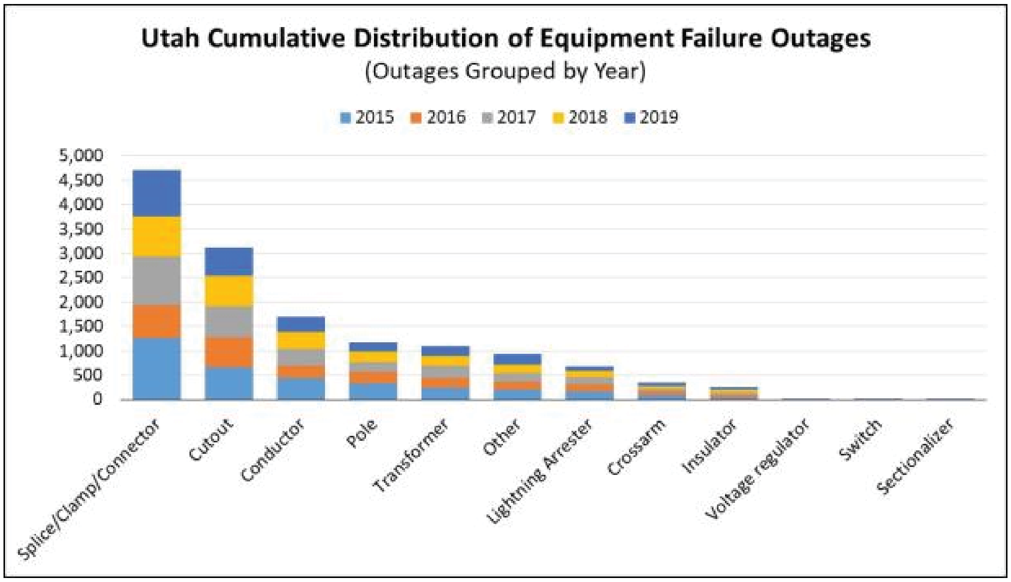

Figure 15. Cumulative Distribution of Equipment Failure Outages

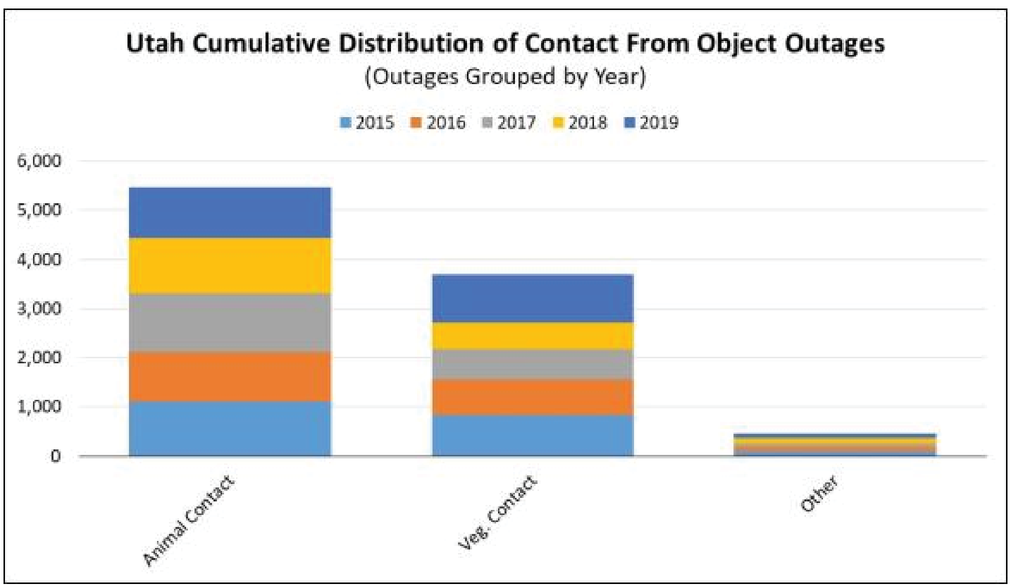

Figure 16. Cumulative Distribution of Contact From Object Outages

1.4.3. Outages During Fire Season

To determine whether any particular outage category occurred more frequently during the fire season, the company also evaluated the outage data from the perspective of time of year. Again using the same outage categories, the analysis counted outages occurring during fire season (June 1 through October 1) versus outages occurring the rest of the year.

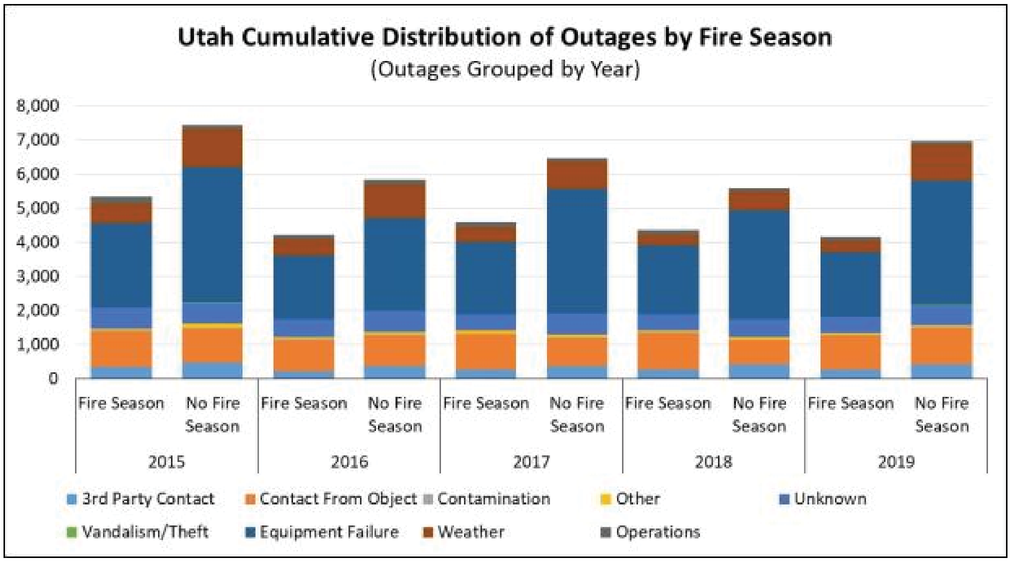

Figure 17. Cumulative Distribution of Outage Category Grouped by Year and Fire Season

This part of the analysis validated that there are no obvious aberrations in the data that would suggest that a particular outage type occurred with overwhelming frequency during fire season. In other words, the two main outage categories, equipment failure and contact from object, remain the largest outage causes, no matter the season. While the other categories remain constant through the year, the equipment failure category experiences the greatest seasonality decreasing during fire season and still remaining the greatest contributor. For this reason – and recognizing the general logic that faults during fire season are the greatest concern for wildfire mitigation – the company focused on the outage totals during fire season. As the data above shows, over the last five years, there has been a downward trend in the number of outages during fire season. One of the goals of this wildland fire protection plan is to continue that trend.

1.4.4. Outages During Fire Season and Within the FHCA

Rocky Mountain Power further analyzed the correlation to outage locations within the FHCA. As discussed above, the greatest risk of catastrophic wildfire is in the FHCA. Consequently, faults in the FHCA reflect the greatest potential ignition risks. Outages in the FHCA correlate to those faults of greatest concern.[9] Consequently, the company identified the number of outages during fire season and in the FHCA. Those numbers are shown in the following table:

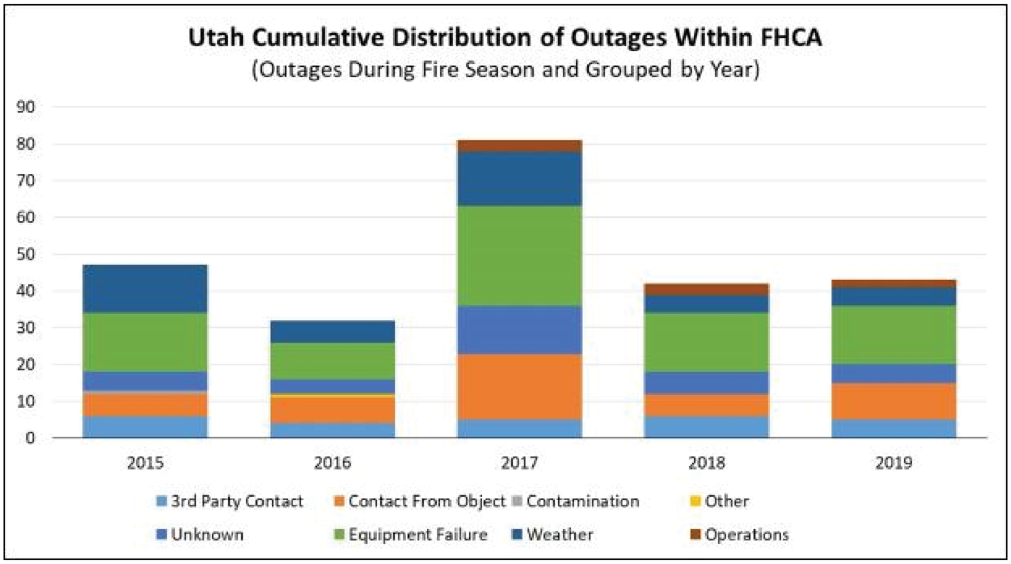

Figure 18. Cumulative Distribution of Outage Category Within FHCA and During Fire Season

This same data is reorganized by general outage categories (and color coded by year), as follows:

[9]There are some constraints on tying outage records to the FHCA. The determination of an FHCA outage is based on the downstream topology within the operating device's Zone of Protection (ZOP). The ZOP of a device includes all lines downstream but not beyond any downstream auto isolating devices. Some portions of the ZOP may touch the FHCA boundary and may not be entirely encompassed within.

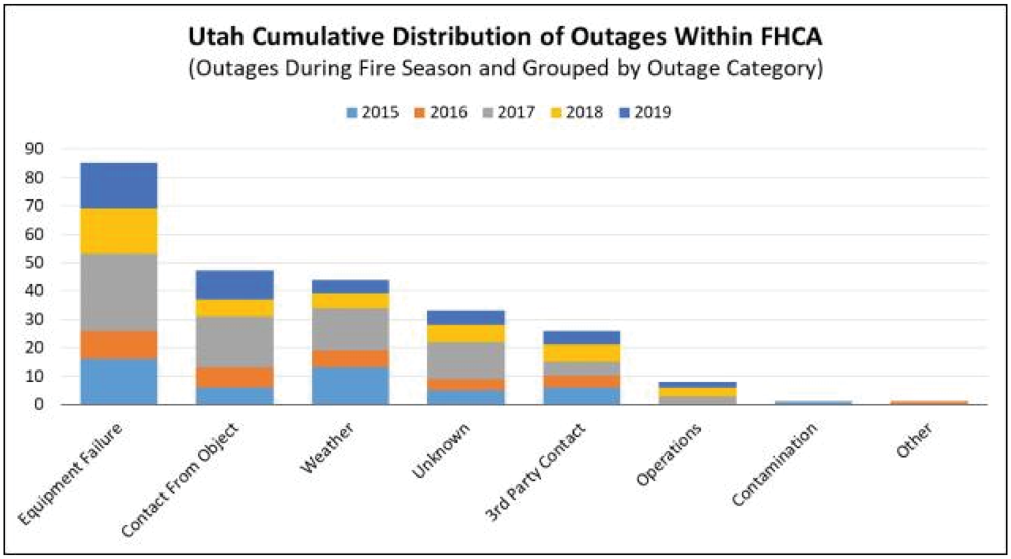

Figure 19. Cumulative Distribution of Outages Within FHCA and During Fire Season by Outage Category

The following figures depict the same data as percentages of the total number of outages during the fire season:

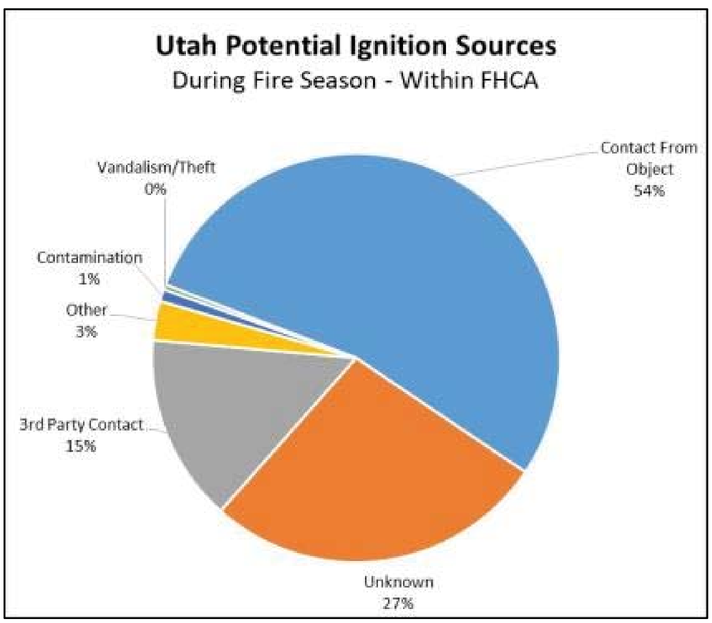

Figure 20. Percentage of Events by Category Within the FHCA, 2015–2019

In sum, this subset of outages, occurring during fire season and in the FHCA, is used as a baseline data set for reference in both designing mitigation strategies aimed at reducing these numbers and measuring performance of the plan on a long-term basis.

1.4.5. Subcategories During Fire Season and Within the FHCA

The complete analysis above affirms the general conclusion that the two categories of greatest concern are contact from objects and equipment failure. As discussed above, Rocky Mountain Power analyzed subcategories within these two leading general categories. Applying that distinction specifically to outages during the fire season and within the FHCA, the results are shown in the figures below:

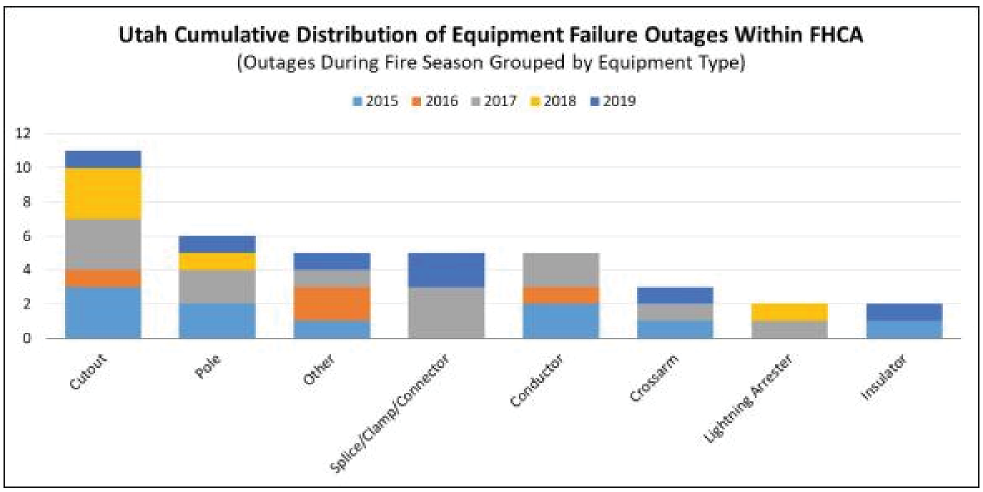

Figure 21. Equipment Subcategories Within the FHCA and During Fire Season

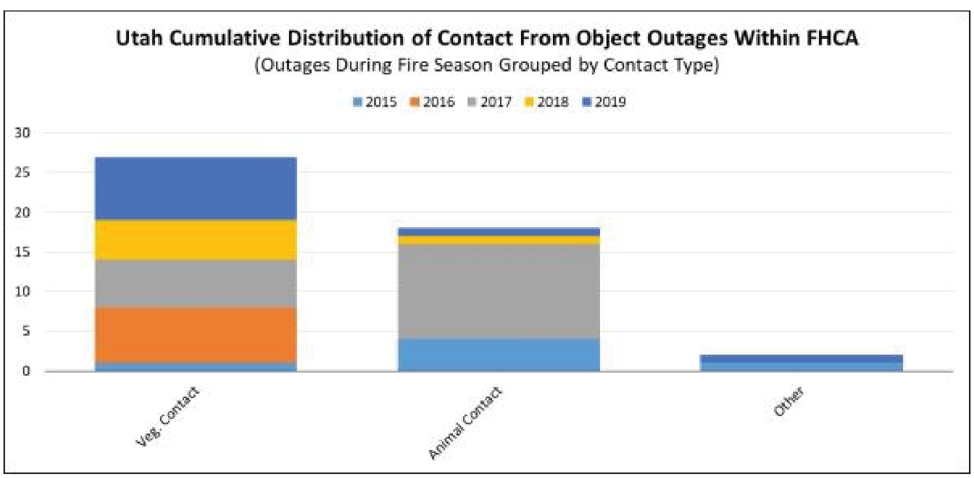

Figure 22. Contact from Object Subcategories Within the FHCA and During Fire Season

1.4.6. Comparison of Outages Outside the FHCA and Within the FHCA

Again using historical data for outages during fire season, the company compared outage rates in the FHCA versus all other areas outside the FHCA. During fire season, equipment failure and contact from object remain the leading outage categories. Together, these categories total 54% of all outages within the FHCA and 68% outside the FHCA. The results of that exercise are shown in the following table and corresponding pie charts for the percent contribution of each outage type in Figure 23.

Table 7. Frequency of Outages by Cause Category

Potential Suspected Initiating Event Type	2015–2019 Total Number of Events During Fire Season in Utah							
	Outside the FHCA				Within the FHCA			
	Rank	Total Events	% Contribution	Events/ Year	Rank	Total Events	% Contribution	Events/ Year
Equipment Failure	1	10,266	46%	2,053	1	85	35%	17
Contact From Object	2	5,045	22%	1,009	2	47	19%	9.4
Unknown	3	2,543	11%	508.6	4	33	13%	6.6
Weather	4	2,079	9%	415.8	3	44	18%	8.8
Third-Party Contact	5	1384	6%	276.8	5	26	11%	5.2
Operations	6	720	3%	144	6	8	3%	1.6
Other	7	293	1%	58.6	7	1	0%	0.2
Contamination	8	90	0%	18	8	1	0%	0.2
Vandalism/Theft	9	37	0%	7.4	9	0	0%	0
Grand Total	**-**	**22,457**	**1**	**4,491**	**-**	**245**	**1**	**49**

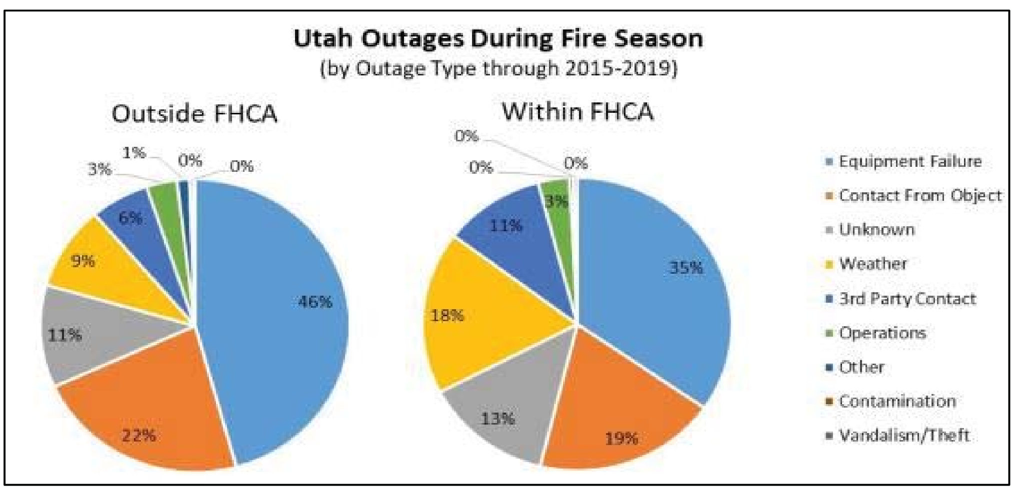

Figure 23. Percent of Outages by Cause Category Occurrence from 2015–2019, Inside and Outside the FHCA

1.5. Risk Assessment Conclusions

While a relatively small percentage of the total number of wildfires are attributable to powerlines, the potential magnitude of any particular wildfire event warrants mitigation efforts. The history of outages on the electrical network, and the faults underlying those outages, reflects the best available data for the wildfire risk assessment. Equipment failure and contact from object presents the greatest utility-related fire risk to Rocky Mountain Power's Utah service territory, together accounting for almost 75% of all outages within the FHCA. Recognizing the reality that a fault is behind those outages, such cause categories also reflect the greatest risk of utility-related wildfires. In contrast, there were relatively few ignition potential events associated with the outage cause categories for third-party contact, contamination and vandalism/theft. As demonstrated by the data, areas inside and outside the FHCA experience the same issues with statistically similar frequency. Equipment failure is a central category of concern. In particular, the number of outages related to fuse operations in the FHCA warrant special focus on that equipment type. Likewise, the data also shows that contact from an object is a greater concern. This data leads to the conclusion that reducing the number of equipment failures and contact-related faults must be the top mitigation priorities. Specific mitigation strategies designed to address these risks are discussed throughout the rest of this plan.

2. Operational Practices

2.1. System Operations

The manner in which an electrical system is operated can mitigate the wildfire risk. Rocky Mountain Power has specific procedures addressing system operations during fire season. These policies are designed to reduce the potential for ignition of a fire from sparks emitted when a line is re-energized despite a disturbance on the line. Recognizing the increasing magnitude of the wildfire risk, the procedures were already significantly revised in June 2018 to incorporate more conservative procedures designed to reduce the potential fault-based ignition on Rocky Mountain Power's electrical network. From a practical perspective, the procedures implicate two primary subject areas: (a) settings for automatic reclosers and (b) line testing after lock-out.

Automatic reclosers are currently deployed on various transmission lines and distribution circuits throughout Rocky Mountain Power's service territory. When a line trips open, an automatic recloser may operate to close the circuit very quickly, so long as the cause of a momentary trip has cleared. The reclosing function allows Rocky Mountain Power to maintain service on a line that had tripped, rather than opening the circuit and de-energizing the line. In general, automatic recloser operation is beneficial because it reduces outages and improves customer reliability. The actual operation of recloser equipment does not directly present wildfire risk, as the recloser equipment itself does not emit sparks or otherwise pose an ignition risk.

The operation of automatic reclosers, however, indirectly implicates some degree of ignition risk. When a fault is detected on the line, a recloser will trip and reclose based on predetermined settings in an attempt to re-energize the line. If the cause of the fault is no longer present when the device recloses, the line will re-energize resulting in limited impact to customers. If the cause of the original fault still remains when the device recloses, however, the original fault may persist and, depending on the circumstances, potentially result in arcing or an emission of sparks. As a result, in some limited circumstances, the second fault scenario could lead to a fire ignition. Accordingly, automatic recloser settings can have a significant impact on wildfire mitigation.

The issue with line-testing on overhead lines is very similar. If a breaker has "locked-out" – meaning that it has opened and no longer conducts electricity – a system operator will sometimes "test" the line. To test the line, the system operator will close the device, thereby allowing the line to be re-energized. If the fault has cleared, then the system will run normally. If the fault has not cleared, the device will lock out again. If the device locks out again, the system operator then knows that additional investigation or work will be required before the line can be successfully re-energized. Because faults are often temporary, line-testing can be an efficient tool to maintain customer reliability. At the same time, line-testing can result in the emission of sparks if a fault has not yet cleared when the line is tested. Accordingly, a "no-test" policy reduces the risk of ignition, and a "no-test" policy is applicable in certain circumstances during fire season.

In general, these system operating procedures are more restrictive when wildfire conditions are more elevated. The specific circumstances in which automatic reclosers are disabled and no-test applies, on both transmission and distribution lines, are fully detailed in the procedures.

2.2. Field Operations

During fire season, Rocky Mountain Power modifies the way it operates in the field to further mitigate wildfire risk. In particular, field operations considers the local weather and geographic conditions that may create an elevated risk of wildfire. These practices are targeted to reduce the potential of direct or indirect causes of ignition during planned work activities, fault response and outage restoration.

Rocky Mountain Power personnel working in the field during fire season mitigate wildfire risk through a variety of tactics. Routine work, such as condition correction and outage response, poses some degree of ignition risk, and, in certain circumstances, crews modify their work practices and equipment to decrease this risk. In the extremely unlikely event that a fire ignition occurs while field crews or other Rocky Mountain Power personnel are working in the field (collectively “field personnel”), such field personnel are equipped with basic tools to extinguish small fires.

Work Restrictions. Rocky Mountain Power field operations is able to mitigate some wildfire risk by managing the way that field work is scheduled and performed. To effectively manage work during fire season, area managers regularly review local fire conditions and weather forecasts provided to them as part of Rocky Mountain Power’s monitoring program – discussed in the situational awareness section below.

During fire season generally, field operations managers are encouraged to defer any nonessential work at locations with dense and dry wildland vegetation, especially during periods where the National Weather Service has issued a *Red Flag Warning* and/or the fire agency having jurisdiction issues a *Fire Restriction* or *Closure Order*. If essential work needs to be performed in the FHCA and other areas with appreciable wildland vegetation, certain restrictions may apply, including:

- **Hot Work Restrictions.** Field operations managers are encouraged to evaluate whether work should be performed during a planned interruption, rather than while a line is energized.
- **Time of Day Restrictions.** Field operations managers are encouraged to consider using alternate work hours to accommodate evening and night work, when there may be less risk of ignition.
- **Wind Restrictions.** Field personnel are encouraged to defer work, if feasible, when there are windy conditions at a particular work site.
- **Driving Restrictions.** Field personnel are encouraged to keep vehicles on designated roads whenever operationally feasible.

Worksite Preparation. If wildland vegetation posing an ignition risk is prevalent at a worksite, and the work to be performed involves the potential emission of sparks from electrical equipment, field personnel working during fire season are encouraged to employ best practices and remove vegetation at the work site where allowed in accordance with land management/agency permit requirements, especially when there is dry or tall wildland grass. In addition to clearing work, the water truck resources, discussed below, are strategically assigned to sometimes accompany field personnel working in a wildland area during fire season, especially in the FHCA. Depending on local conditions, dry vegetation in the immediate vicinity may be sprayed with water before work as a preventative measure.

Additional Labor Resources. Some wildfire mitigation activities require the time of field personnel, including in two key areas: (a) supporting system operations in administering the procedures discussed above and (b) responding to outages during fire season. The increased operations cost associated with these activities will be tracked and included in the annual report filed in conjunction with this plan.

Under normal operating procedures, system operators and field personnel work together on a daily basis to manage the electrical network. In many situations, system operators depend on field personnel to gather information and assess local conditions. As discussed above, there are system operations procedures during wildfire season for disabling automatic recloser functions and limiting line-testing. Consequently, system operators need field personnel to gather information and assess local conditions during fire season more frequently than would otherwise be required under normal operating procedures. The requests from system operators may be varied, ranging from a simple phone call to confirm that it is raining in a particular area, to a much more time-intensive request, such as a full line patrol on a circuit.

Field personnel may also spend some additional time when responding to an outage during fire season. After a fault results in an outage, all or part of a circuit might remain de-energized while restoration work is performed, depending on the design, loading conditions and sectionalizing capability of the circuit experiencing the outage. Occasionally, additional foreign objects, such as tree limbs or other debris, can come into contact with the de-energized line and remain undetected throughout the duration of restoration efforts. Under normal operating procedures and consistent with prudent utility practices, a line is typically re-energized as soon as restoration work is complete. Consequently, a re-energized line could immediately experience a new fault if some contact between the line and foreign object had occurred while restoration work was being performed. The new fault would, of course, present additional wildfire risk, because of the potential of a spark being emitted as a result of a fault occurring when the line was re-energized. To mitigate this risk, field operations may perform, during fire season and particularly in the FHCA, depending on current conditions at the work site and the duration of the restoration work, some amount of line patrol on certain de-energized sections of the circuit. Depending on the circumstances, this extra patrol might be done just before or just after re-energizing the line. Typically, this type of line patrol does not involve a close inspection of any particular facility; instead, it is a quick visual assessment specifically targeted to identify obvious foreign objects that may have fallen into the line during restoration work.

Basic Personal Suppression Equipment. Personal safety is the first priority, and Rocky Mountain Power field personnel are encouraged to evacuate and call 911 if necessary. Field personnel working in the FHCA maintain the capability to extinguish a small fire that ignited while they are working in the field. Field personnel should attempt suppression only if the fire is small enough so that one person can effectively suppress the fire while maintaining their personal safety. All field personnel working in the FHCA during fire season will have basic suppression equipment available onsite, because field utility trucks typically carry the following equipment: (1) fire extinguisher; (2) shovel; (3) Pulaski; (4) water container; and (5) dust mask. The water container should hold at least five gallons and may be a pressurized container or a backpack with a manual pump.

Mobile Generators. Rocky Mountain Power has a small number of mobile generators to assist with emergency response efforts. In short, when power on the electrical network is lost, either proactively or as the result of wildfire damage, a mobile generator unit can be dispatched to provide power. The generator is transported via tractor trailer to a specific location based on real-time circumstances. For example, a mobile generator may be dispatched by the Emergency Operations Center to mitigate the impact of a proactive de-energization, as discussed in greater detail in the Public Safety Power Shutoff section below. There are constraints in connecting the generator, and each deployment is examined on a case-by-case basis. As part of this wildland fire protection plan, Rocky Mountain Power plans to purchase three 425 kW mobile generators.

Water Truck Resources. Rocky Mountain Power has water trucks that field operations use to mitigate against wildfire risk. These resources are not dispatched to reported fires (i.e., like a fire truck). Instead, Rocky Mountain Power resources are strategically assigned to accompany field personnel. If conditions are warranted the Emergency Operations Center or incident commander can strategically assign water truck resources to accompany field personnel. For example, if it is necessary to perform work in the FHCA during a period in which there is a *Red Flag Warning*, Rocky Mountain Power field operations may schedule a water truck to join field personnel working in the field. As discussed above, the water truck can be used to help prep the site for work. By watering down dry vegetation in the work area, any chance of an ignition can be minimized. Field operations currently has eight water trucks for use in such applications. In addition, the company plans to purchase two water trucks and one trailer. The locations and types of existing water truck resources owned by Rocky Mountain Power are listed in the following table.

Table 8. Water Truck Resources

Mobile Equipment	Location	Contact
1 ton – 4×4 Water Truck (72197)	Salt Lake City, UT	Operations manager
1 ton – 4×4 Water / Line Patrol Truck (72730)	American Fork, UT	Operations manager
1.5 ton – 4×4 Water Truck (74631)	American Fork, UT	Operations manager
1 ton – 4×4 Water Truck (76352)	American Fork, UT	Operations manager
1 ton – 4×4 Water Truck	American Fork, UT	Operations manager
1 ton – 4×4 Water Truck	Park City, UT	Operations manager
1 ton – 4×4 Water Truck	Cedar City, UT	Operations manager
1 ton – 4×4 Water Truck	Salt Lake City, UT	Operations manager

3. Inspection and Correction

Inspection and correction programs are the cornerstone of a resilient system. These programs are tailored to identify conditions that could result in premature failure or potential fault scenarios, including situations in which the infrastructure may no longer be able to operate per code or engineered design, or may become susceptible to external factors, such as weather conditions.

Rocky Mountain Power performs inspections on a routine basis as dictated by both state-specific regulatory requirements and Rocky Mountain Power-specific policies. When an inspection is performed on a Rocky Mountain Power asset, inspectors use a predetermined list of condition codes (defined below) and priority levels (defined below) to describe any noteworthy observations or potential noncompliance discovered during the inspection. Once recorded, Rocky Mountain Power uses condition codes to establish the scope of and timeline for corrective action to make sure that the asset is in conformance with National Electric Safety Code (NESC) requirements, state-specific code requirements and/or Rocky Mountain Power specific policies. This process is designed to correct conditions while reducing impact to normal operations.

Key terms associated with Rocky Mountain Power's Inspections & Corrections Program are defined as follows:

- **Detailed Inspection.** A careful visual inspection accomplished by visiting each structure, as well as inspecting spans between structures, which is intended to identify potential nonconformance with the NESC or other applicable state requirements, nonconformance with Rocky Mountain Power construction standards, infringement by other utilities or individuals, defects, potential safety hazards, and deterioration of the facilities that need to be corrected to maintain reliable and safe service.

- **Pole Test & Treat.** An inspection of wood poles to identify decay, wear or damage, which may include pole-sounding, inspection hole drilling, and excavation tests to assess the pole condition and identify the need for any repair, or replacement and apply remedial treatment according to policy.
- **Visual Assurance Inspection.** A brief visual inspection performed by viewing each facility from a vantage point allowing reasonable viewing access, which is intended to identify damage or defects to the transmission and distribution system, or other potential hazards or right-of-way-encroachments that may endanger the public or adversely affect the integrity of the electric system, including items that could potentially cause a spark.
- **Condition.** The state of something with regard to appearance, quality, or working order that can sometimes be used to identify potential impact to normal system operation or clearance, which is typically identified by an inspection.
- **Condition Codes.** Predetermined list of codes for use by inspectors to efficiently capture and communicate observations and inform the scope of and timeline for potential corrective action.
- **Correction.** Scope of work required to remove a condition within a specified timeframe.
- **Priority Level.** The level of risk assigned to the condition observed, as follows:
  - Imminent – imminent risk to safety or reliability
  - Priority A – risk of high potential impact to safety or reliability
  - Priority B – low to moderate risk to safety, reliability or worker safety
  - Priority D – issues that are not NESC conformance issues that are recorded for informational purposes
  - Priority G – grandfathered conditions that conformed to NESC requirements that were in place when construction took place but do not conform to more current code revisions

3.1. Current Inspection and Correction Programs

Rocky Mountain Power's asset inspection program involves three primary types of inspections: (1) visual assurance inspection; (2) detailed inspection, and (3) pole test & treat. Inspection cycles, which dictate the frequency of inspections, are set by Rocky Mountain Power asset management. In general, visual assurance Inspections are conducted more frequently, to quickly identify any obvious damage or defects that could affect safety or reliability, and detailed inspections are performed less frequently, with a more detailed scope of work. The frequency of pole test & treat is based on the age of wood poles, and such inspections are typically scheduled in conjunction with certain detailed inspections. The inspector conducting the inspection will assign a condition code to any conditions found and the associated priority level in Rocky Mountain Power's facility point inspection (FPI) system. Corrections are then scheduled and completed within the correction timeframes established by Rocky Mountain Power asset management, as discussed below. While the same condition codes are used throughout Rocky Mountain Power's service territory, the timeframe for corrective action is different in different state jurisdictions. In all cases, the timeline for corrections takes into account the priority level of any identified condition. A priority A condition is addressed on a much shorter timeframe than a priority B condition.

3.2. Proposed Inspection and Correction Programs

The existing inspection and correction programs are effective at maintaining regulatory compliance and managing routine operational risk. They also mitigate wildfire risk by identifying and correcting conditions that, if uncorrected, could ignite a fire. Nonetheless, recognizing the growing risk of wildfire, asset management proposes to supplement existing programs to mitigate the growing wildfire-specific operational risks and create greater resiliency against wildfires. There are three primary elements to this proposal: (1) creating a fire risk condition classification; (2) increasing inspection frequencies in Fire High Consequence Areas (FHCA); and (3) narrowing correction timeframes for fire risk conditions.

Fire Risk Conditions. Rocky Mountain Power now designates certain conditions as "fire risk conditions." Each condition is still assigned a condition code (e.g., CONDFRAY for a damaged or frayed primary conductor) – but certain condition codes are categorically designated as a fire risk condition. Accordingly, if a condition is designated under a particular condition code associated as a fire risk, the condition will also be designated as a fire risk condition. To this end, a review was performed on all existing condition codes to determine whether the condition code could have any correlation with fire ignition. Condition codes reflecting an appreciable risk of fire ignition were designated as fire risk conditions. For example, if a damaged or frayed primary conductor was observed during an inspection, the inspector would record condition code CONDFRAY, which is designated as a fire risk condition because the condition could eventually result in an ignition under certain circumstances. In contrast, the observation of a missing or broken guy marker would result in the condition code GUYMARK, which is not designated as a fire risk condition.

Inspection Frequency. Asset management also plans to increase the frequency of all three inspections types for assets located in the FHCA. Consistent with industry best practices, inspections are Rocky Mountain Power's preferred mechanism to identify conditions. An increase in the frequency of inspections will result in more timely identification of potential fire risk conditions. Inspection frequencies for Utah asset types are summarized in the following table:

Table 9. Current and Proposed Inspection Frequency in the FHCA

Inspection Type	Current Inspection Frequency in years)	Proposed Inspection Frequency (in years)
OH Distribution (Less than 46 kV)		
Visual	2	1
Detailed	20	5
Pole Test & Treat	n/a	10
OH Local Transmission (more than 46 kV and Less than 200 kV)		
Visual	2	1
Detailed	10	5
Pole Test & Treat	10	10
OH Main Grid (More than 200 kV)		
Visual	1	1
Detailed	2	2
Pole Test & Treat	10	10

Correction Timeframe. Rocky Mountain Power will further mitigate wildfire risk by reducing the time allowed for correction of fire risk conditions in the FHCA. As expressed above, certain types of conditions have been identified as having characteristics associated with a higher risk of wildfire potential. Accordingly, Rocky Mountain Power is prioritizing those conditions for correction. Because of the risk of catastrophic wildfire in the FHCA, Rocky Mountain proposes an aggressive correction schedule for fire risk conditions in the FHCA, requiring that priority A conditions be corrected on a 60-day average and that B fire risk conditions be corrected within 12 months. Correction timeframes for fire risk conditions in the FHCA are summarized in the following table:

Table 10. Current and Proposed Correction Timeframes for Fire Risk Conditions in the FHCA

Condition	Current Correction Timeframes	Proposed Correction Timeframes
A – imminent	Immediate	Immediate
A – fire risk and in the FHCA	120 days on average	60 days on average
B – fire risk and in the FHCA	not specified	12 months

4. Vegetation Management

Good vegetation management is generally recognized as a significant strategy in any wildland fire protection plan. Contact between vegetation and a power line can be a source of fire ignition. Thus, reducing vegetation contacts reduces the potential of an ignition originating from electrical facilities. While it would be virtually impossible to eliminate vegetation contacts completely, at least without radically altering the landscape near power lines, a primary objective of Rocky Mountain Power's existing vegetation management program is to minimize contact between vegetation and power lines. This objective is in alignment with core wildland fire protection efforts, and continuing dedication to administering existing programs is a solid foundation for Rocky Mountain Power's wildland fire protection efforts. To supplement the existing program, Rocky Mountain Power vegetation management is implementing additional wildland fire protection strategies in Fire High Consequence Areas (FHCA).

4.1. Regular Vegetation Management Program

Rocky Mountain Power's vegetation management program is described in detail in Rocky Mountain Power's Transmission & Distribution Vegetation Management Program Standard Operating Procedures ("Standard Operating Procedures"). The focus of Rocky Mountain Power's vegetation management efforts is different for distribution lines and transmission lines. In both cases, typical work functions include pruning and tree removals. Rocky Mountain Power prunes trees to maintain a safe distance between tree limbs and power lines. Rocky Mountain Power also removes trees that pose an elevated risk of falling into a power line. But Rocky Mountain Power uses significantly more restrictive clearance protocols under transmission lines and typically has wider rights-of-way to remove vegetation. Similar to other utilities, Rocky Mountain Power contracts with vegetation management service providers to perform the pruning and tree removal work for both transmission and distribution lines.

Distribution – Cycle Maintenance. Vegetation management on distribution circuits is completed on a cyclical basis. In Rocky Mountain Power's Utah service territory, distribution work is done on a three-year cycle. All vegetation on a given circuit scheduled for work is pruned to comply with defined minimum clearance specifications. Because some trees grow faster than others, minimum clearance specifications vary depending on the type of tree being pruned. For example, faster growing trees need a greater minimum clearance to maintain clearance throughout cycle.

Rocky Mountain Power also integrates spatial concepts to distinguish between side clearances, under clearances and overhang clearances. Recognizing that certain trees grow vertically faster than other trees, it is appropriate to use an increased clearance when moderate- or fast-growing trees are under a conductor. Increasing overhang clearances also reduces the potential for any contacts due to falling overhang.

The minimum clearance specifications are designed so that clearance with primary lines will be maintained throughout the cycle. The specific lengths for the minimum clearance specifications are set forth in Section 5.2 of the Standard Operating Procedures as follows:

Table 11. Distribution Minimum Vegetation Clearance Specifications for a Three-Year Cycle

Three-Year Cycle			
	Slow Growing (< 1 ft./yr.)	**Moderate Growing (1-3 ft./yr.)**	**Fast Growing (>3 ft./yr.)**
Side Clearance	8 ft.	10 ft.	12 ft.
Under Clearance	10 ft.	12 ft.	14 ft.
Overhang Clearance	12 ft.	12 ft.	12 ft.

When a tree is pruned, natural target pruning techniques are used to protect the health of a tree. Natural targets are the final pruning cut location at a strong point in a tree's disease defense system, which are branch collars and proper laterals. Pruning at natural targets protects the joining trunk or limb.[10] Consequently, an actual cut is typically beyond the minimum clearance distance listed in the table above. In all cases, however, the cut is at least to the minimum clearance distance.

Rocky Mountain Power also removes all high-risk trees as part of distribution cycle work, to minimize vegetation contact. High-risk trees are defined in the Standard Operating Procedures as "dead, dying, diseased, deformed, or unstable trees that have a high probability of falling and contacting a substation, distribution or transmission conductors, structure, guys or other Rocky Mountain Power electric facility."[11] Inspections are performed on distribution lines in advance of distribution cycle maintenance work, to identify which trees will be worked in the cycle, including high-risk trees subject to removal. To identify hazard trees, Rocky Mountain Power uses the practices set forth in ANSI A300 (Part 9); Smiley, Matheny and Lilly (2011), Best Management Practices: Tree Risk Assessment, International Society of Arboriculture; and Cal Fire Power Line Fire Prevention Field Guide §§ 12-19. In summary, Rocky Mountain Power uses an initial Level 1 assessment, as defined in ANSI A300 (Part 9), with particular attention to the prevailing winds and trees on any uphill slope. Suspect trees are subjected to a Level 2 assessment, as outlined in ANSI A300 (Part 9), to further assess their condition. After the work is completed, Rocky Mountain Power conducts post-work inspections as part of an audit and quality review process.

Distribution cycle work also includes work designed to reduce future work volumes. In particular, volunteer saplings, small trees that were not intentionally planted, are typically removed if they could eventually grow into a power line. From a long-term perspective, this type of inventory reduction helps mitigate wildfire risk by eliminating a potential vegetation contact long before it could ever occur.

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[10]This technique is drawn from ISA Best Management Practices: Tree Pruning (Gilman and Lilly 2002) and A300 (ANSI 2008). (See also Miller, Randall H., 1998. Why Utilities "V-Out" Trees. Arborist News. 7(2):9-16.)
[11]See Table 2 of FAC-003-04, available at
https://www.nerc.com/pa/Stand/Reliability%20Standards/FAC-003-4.pdf

Transmission Line Vegetation Management. Vegetation management on transmission lines is also focused on maintaining clearances, but the clearance distances are greater. Because of the nature of transmission lines, wider rights-of-way generally allow Rocky Mountain Power to maintain clearances well in excess of the required minimum clearances set forth in the "Minimum Vegetation Clearance Distance" (MVCD[12]). Accordingly, rather than scheduling vegetation management work for transmission lines on a fixed cycle timeframe, such work is scheduled on an as-needed basis, depending on the results of regular inspections and specific local conditions. To determine whether work is needed, an "Action Threshold" is applied, meaning that work is done if vegetation has grown within the action threshold distance. When work is completed, vegetation is cleared to the minimum clearance as specified in this table:

Table 12. Transmission Minimum Vegetation Clearance by Transmission Line Voltage

Transmission Clearance Requirements (in feet)								
	500 kV	**345 kV**	**230 kV**	**161 kV**	**138 kV**	**115 kV**	**69 kV**	**45 kV**
Minimum Vegetation Clearance Distance (MVCD)	8.5	5.3	5.0	3.4	2.9	2.4	1.4	N/A
Action Thresholds	18.5	15.5	15.0	13.5	13.0	12.5	10.5	5
Minimum Clearances Following Work	50	40	30	30	30	30	25	20

Taking advantage of greater legal rights to manage the vegetation in the right-of-way for transmission lines, Rocky Mountain Power employs "Integrated Vegetation Management" (IVM) practices to prevent vegetation growth from ever violating clearances. Rather than depending on pruning in regular work cycles, IVM seeks to prevent clearance issues from ever emerging, by managing the species of trees and other vegetation growing in the right-of-way. Under such an approach, Rocky Mountain Power removes tree species that could potentially threaten clearance requirements, while encouraging cover vegetation, which would never implicate clearance issues.

Line patrolmen inspect most transmission lines annually and notify the vegetation management department of any vegetation conditions. Regional foresters in the vegetation management department also conduct regular inspections of vegetation near transmission lines, including annual inspections of vegetation on all main grid transmission lines. Vegetation work is scheduled dependent on a number of local factors, which is consistent with industry standards and best management practices. Vegetation work on local transmission overbuild is completed on the distribution cycle schedule and inspected accordingly.

[12]See Table 2 of FAC-003-04, available at https://www.nerc.com/pa/Stand/Reliability%20Standards/FAC-003-4.pdf

All of these strategies and techniques are described in much greater detail in the Standard Operating Procedures. The current form of the Standard Operating Procedures was first published in 2008, and periodic updates to content have been made. The most current version is Revision 07, dated August 19, 2019.

4.2. New Wildland Fire Protection Strategies

After identifying lines in the FHCA, Rocky Mountain Power implemented three new elements to its long-term vegetation management program for the purpose of further mitigating wildfire risk in those areas. First, Rocky Mountain Power vegetation management is now doing annual vegetation inspections on all lines in the FHCA, with correction work also completed based on those inspection results. Second, vegetation management increased the minimum clearance distances applicable to distribution cycle work completed in the FHCA. Third, vegetation management now completes annual pole clearing on subject equipment poles located in the FHCA.

Annual Vegetation Inspection. With a program that started in 2019, Rocky Mountain Power vegetation management now conducts annual vegetation inspections for all lines located in the FHCA. Although conducting annual vegetation inspections is above and beyond traditional industry standards, Rocky Mountain Power vegetation management believes that this tool is the most effective strategy to identify high-risk trees at the earliest stage possible. This strategy facilitates removal of high-risk trees before such trees could ever fall into a line and cause a wildfire.

Each year, before the height of fire season, a vegetation inspection will be completed on all lines in the FHCA by a qualified arborist. Consistent with existing procedures, a Level 1 assessment will be conducted to identify any trees that may have become high-risk trees over the course of the prior year; suspect trees are subjected to a Level 2 assessment, as outlined in ANSI A300 (Part 9). In addition, as an additional supplement to normal distribution cycle work, the inspector will identify for pruning or removal vegetation that is likely to violate minimum clearance distances before the next annual inspection.

In conjunction with such annual inspections, vegetation management shall annually complete correction work based on the inspection results, including the prompt removal of all high-risk trees identified during the annual vegetation

Extended Clearances. Rocky Mountain Power has also adopted increased minimum clearance specifications for any distribution cycle work in the FHCA. The new minimum clearance specifications require pruning to at least 12 feet, in all directions and for all types of trees. As discussed above, minimum clearance specifications dictate the distance achieved after pruning is completed. By increasing the minimum distance required at the time pruning is done, Rocky Mountain Power further minimizes the potential of vegetation contacting a power line at any time. The proposed minimum clearance specifications for the FHCA are as follows:

Table 13. Distribution Minimum Vegetation Clearance Specifications in the FHCA

FHCA			
	Slow Growing (< 1 ft./yr.)	**Moderate Growing (1-3 ft./yr.)**	**Fast Growing (>3 ft./yr.)**
Side Clearance	12 ft.	12 ft.	14 ft.
Under Clearance	12 ft.	14 ft.	16 ft.
Overhang Clearance	12 ft.	14 ft.	14 ft.

By increasing distances to at least 12 feet, Rocky Mountain Power vegetation management will meet or exceed industry standards and best practices. While certain fast-growing trees can sometimes exceed expected annual growth, these minimum clearance specifications are designed with the expectation that such clearances achieved at the time of work will result in vegetation likely never impinging a 4-foot clearance at any time before the next work cycle.

Pole Clearing. Rocky Mountain Power vegetation management performs pole clearing on subject equipment poles located in the FHCA. Pole clearing involves removing all vegetation within a 10-foot radius cylinder of clear space around a subject pole and applying herbicides and soil sterilants to prevent any vegetation regrowth (unless prohibited by law or the property owner). This strategy is distinct from the clearance and removal activities discussed above because it is not designed to prevent contact between vegetation and a power line. Instead, pole clearing is designed to reduce the risk of fire ignition if sparks are emitted from electrical equipment. Pole clearing will be performed on wildland vegetation in the FHCA around poles that have fuses, air switches, clamps or other devices that could create sparks. After a pole has been cleared, a spark falling within the 10-foot radius would be much less likely to ignite a fire.

Alternative Strategies for Potential Future Deployment. Moving forward, Rocky Mountain Power vegetation management is planning to implement the three mitigation projects described above. Rocky Mountain Power will consider and evaluate other strategies and emerging industry standards and best practices in the arena of wildfire mitigation. Along these lines, Rocky Mountain Power may implement additional vegetation management strategies in a subsequent wildland fire protection plan. In particular, Rocky Mountain Power vegetation management is considering whether certain strategies might be employed to reduce the general inventory of trees that could fall into a line.

Vegetation Inventory Reduction Projects. Rocky Mountain Power vegetation management has experimented with inventory reduction projects aimed at reducing the overall volume of trees with the potential to create clearance issues or become high risk at some point in the future. Pacific Power is experimenting with some inventory reductions programs as part of its wildfire mitigation plan in California. Depending on the results of those projects, Rocky Mountain Power vegetation management may consider implementing similar projects in Utah.

The goal of inventory reduction is to remove trees before such trees ever require vegetation work. Unless property rights in the right-of-way were substantially enlarged, it would not be feasible to remove all trees that have the potential to implicate clearance issues or become high-risk trees (i.e., by definition, all trees eventually become high-risk trees when they die). Instead, an inventory reduction program targets specific areas of particular concern, with the goal of materially reducing the total number of trees that could eventually pose a risk of vegetation contact. Determining which areas and trees to target implicates a certain degree of subjective judgment and evaluation of local conditions. Factors for consideration include tree species, tree height, weather patterns, topography, line design and tree disease patterns.

Right-of-Way Enhancements. Vegetation management practices are typically limited by Rocky Mountain Power's legal rights in the right-of-way. Width of the defined right-of-way is obviously a key factor. On higher voltage transmission lines, wide easements permit vegetation management to use IVM practices and maintain generous clearance distances. Not surprisingly, there are very few vegetation contacts on lines located in those very wide easements. If similar width easements were obtained for lower voltage transmission and distribution facilities in the FHCA, similar vegetation management practices could be employed. The primary barriers to this approach are cost and aesthetics. Obtaining additional property rights entails additional capital investment. In terms of aesthetics, distribution facilities located near residential structures frequently overlap with areas where customers are particularly concerned with the landscape. Nonetheless, strategies might be considered to address such concerns. First, the costs of additional easements rights may be reduced by solely obtaining rights to remove tree species that could, when mature, grow tall enough to strike a power line in the more narrowly defined utility right-of-way. Second, aesthetic concerns might be addressed by focusing on line miles where there are few residential structures near the line.

Lines traversing public lands pose distinct challenges, as land managers have frequently been opposed to vegetation management activities outside the proscribed width of the right-of-way specified by permit. With growing concerns about wildfire, however, many public bodies are reassessing land management policies. The relatively recent passage of legislation by the U. S. Congress suggests that utility companies may receive wider latitude in their vegetation management activities in the future. Section 211 of the Omnibus Appropriations Act of 2018 amended Title V of the Federal Land Policy and Management Act. The new law, codified at 43 U.S.C.A. § 1772, establishes a formal procedure for submission and approval of vegetation management plans, with an emphasis on standardized, consistent plans that minimize the need for case-by-case approvals for high-risk tree removal. Rocky Mountain Power understands that the Bureau of Land Management (BLM) and the United States Forest Service (USFS), the two federal agencies that issue most of Rocky Mountain Power's rights-of-way permits, are engaged in a rulemaking to "develop a consolidated and coordinated process for the review and approval of plans." 43 U.S.C.A. § 1772(c)(4)(A). When those regulations are finalized, Rocky Mountain Power anticipates that it will submit a vegetation management plan under 43 U.S.C.A. § 1772(c)(1) to both the BLM and the USFS. Rocky Mountain Power is hopeful that those submissions will eventually result in permission to conduct vegetation management activities on a wider right-of-way path.

5. Environmental

Rocky Mountain Power is developing a Wildlife Protection Plan (WPP) focused on preventing wildlife contacts in the FHCA and other areas where species, habitat, utility equipment and other factors can present elevated wildfire risk. The WPP is being modelled after the methods and standards developed in Rocky Mountain Power's Avian Protection Plan (APP), which has been implemented for several decades and significantly improved over time. The APP has proven effective in reducing bird mortality and associated reliability risks, and it can serve as a model for similar efforts to address wildfire risks caused by other animals. The overall benefit of a WPP is to directly reduce the risk of fires and outages associated with wildlife-electrical contacts in targeted areas.

5.1. Description of the Existing Avian Protection Plan

Rocky Mountain Power's service territory supports a diverse array of migratory birds and other wildlife[13] that have the potential to interact with its electrical facilities. Rocky Mountain Power has developed and implemented an APP addressing operations within its Utah service territory in cooperation with the U.S. Fish and Wildlife Service (USFWS), which identifies processes to minimize avian electrocutions and collisions with electrical facilities that may result in an avian mortality or injury and subsequent potential for a disruption in electrical service. The APP outlines Rocky Mountain Power policies and procedures for responding to bird mortalities and nests; avian protection standards for transmission, distribution and substation facilities; and risk assessment procedures to identify areas in which to implement proactive facility retrofits to reduce electrocution and collision risks of protected birds. Retrofit refers to actions taken to modify a structure to prevent avian or wildlife mortalities. This may include installation of after-market bird protection products (such as covers), reframing to achieve avian-safe separations

[13]For purposes of this plan, "wildlife" refers to and includes nonprotected birds (e.g., birds that are not listed under the Migratory Bird Treaty Act [MBTA], Endangered Species Act [ESA], and/or Bald and Golden Eagle Protection Act [BGEPA]) and mammals or other wild animals that may climb, land on, or interact with electrical infrastructure. This may include state and/or federally protected nonavian species (e.g., threatened/endangered species) and nonprotected species. Examples of "wildlife" that may interact with electrical infrastructure include raccoons, squirrels, climbing snakes, starlings, rock doves, collared doves, etc.

between wires, or rebuilding structures to meet avian-safe designs. Rocky Mountain Power's program was used as a template for the national APP guidelines developed by Avian Power Line Interaction Committee (APLIC) and the USFWS in 2005. Rocky Mountain Power's APP is a living document that is reviewed and updated as needed through coordination with the USFWS. The APP includes standardized program components for Rocky Mountain Power transmission and distribution operations and includes proactive survey and retrofitting efforts prioritized by avian risks at different circuits.

Although Rocky Mountain Power's APP and related policies were developed with a focus on protecting eagles, other raptors and other migratory birds from electrocution and collision mortality, APP activities also mitigate wildfire risk associated with these types of incidents. In addition, APP efforts provide secondary benefits of minimizing other wildlife contacts, involving nonprotected birds and mammals, further mitigating the wildfire risk associated with those incidents. Finally, existing APP procedures also address potential fire risks posed by bird nests and provide wildland fire protection in facilitating the removal or safe relocation of bird nests.

In 2009, Rocky Mountain Power's transmission and distribution operations developed and implemented two policies: (1) Avian Protection Plan Policy and (2) Bird Protection Policy for Substations that address management of protected bird incidents with Rocky Mountain Power-owned distribution, transmission and substation facilities. These policies outline Rocky Mountain Power's avian-safe construction design standards, which include requirements to construct and design all new or rebuilt equipment poles in all areas and all new or rebuilt lines in rural areas in adherence with Rocky Mountain Power's avian-safe constructions standards, thereby reducing the risk of protected bird or other wildlife incidents. Rocky Mountain Power implements these policies throughout its service territory.

Rocky Mountain Power's avian-safe construction design standards follow APLIC guidance documents: Suggested Practices for Avian Protection on Power Lines: The State of the Art in 2006 and Reducing Avian Collisions with Power Lines: State of the Art in 2012. Avian-safe designs for transmission and distribution structures are achieved by framing poles with 60-inch horizontal and 40-inch vertical phase-to-phase and phase-to-ground separation, extending the center phase of a three-phase crossarm design 36 inches from the crossarm (pole), or by using covers to protect against potential phase-to-phase and phase-to-ground contact by birds or other wildlife. Phase-to-phase and phase-to-ground separation distances are based on the skin-to-skin dimensions of eagles as recommended by APLIC for utilities located in areas where eagle interactions may occur. Because eagle interactions within substations are unlikely, Rocky Mountain Power's avian-safe substation standards are based on the measurements of the largest birds commonly observed in substations and are sufficient for the protection of hawks, owls, ravens and smaller birds. Consequently, Rocky Mountain Power's avian-safe substation designs apply covers or barriers where there is less than 30 inches of vertical separation and/or less than 46 inches of horizontal/diagonal separation between phase-to-phase or phase-to-ground potential points of contact. Line markers are used as needed to minimize avian collision risks. Nest management – potentially including nest discouraging, removal or relocation – may be employed as needed to address nests that pose fire, safety, reliability or bird electrocution risks. Rocky Mountain Power maintains and complies with applicable federal and/or state permits authorizing management of migratory bird nests and handling of carcasses. All avian protection standards and products are reviewed periodically and updated to ensure that the best available products and methods are being used.

5.2. Description of the New Wildlife Protection Plan

While many elements of the existing APP program already provide some degree of wildland fire protection, expansion of certain activities can enhance these efforts. As indicated above, Rocky Mountain Power T&D environmental services proposes to develop and implement a WPP that will leverage proven APP practices and methodologies and, where needed, apply new approaches to respond to wildlife incidents and implement proactive measures. The ultimate goal of the proposed WPP is to reduce the potential for wildlife incidents within FHCA boundaries and emerging focal areas.

To be clear, the WPP will be funded separately from current funding commitments made to implement the APP, as APP priorities are based on agreements with federal and state agencies to address potential risks to protected birds. The WPP draws from the experience and knowledge gained through APP implementation, and integrates applicable elements of the APP, but the WPP does not replace the APP. Along these lines, the WPP is intended to complement, not contradict APP components. The section below provides more detail regarding these components. The WPP will be a living document and updated as appropriate.

Incident Tracking. In conjunction with existing APP activities, Rocky Mountain Power tracks reported protected bird incidents and nest management activities using Rocky Mountain Power's Wildlife Incident Tracking System (WITS). Data stored in WITS includes species, location, outage identification numbers and remedial actions (typically retrofitting the structure where the incident occurred) through completion. Data in WITS is also used to identify potential areas of high risk for avian incidents and focal zones to implement proactive retrofitting efforts.

Within FHCA boundaries, we propose to evaluate existing outage and GIS data to assess wildlife incident risks, frequency, associated structure types and locations. This information will be used to identify possible correlations between wildlife interactions, structure/equipment type, and habitat that can then prioritize remedial actions to address wildlife incidents. In addition, similar factors outside of the FHCA will be considered as possible emerging focal areas. Existing data sources and software will be assessed to determine appropriate reporting needs for wildlife incidents, and to seek efficiencies with existing IT resources. Applicable guidance will be developed and distributed to affected employees in these areas. This would be a Rocky Mountain Power-wide effort, so the cost of an IT solution would be shared throughout Rocky Mountain Power T&D operations, and employee time associated with reporting and tracking incidents would be included with T&D operations and environmental services departments for Rocky Mountain Power.

Reactive Actions. Consistent with the APP identifies, Rocky Mountain Power responds to avian incidents by taking remedial action, which include retrofitting the pole where the incident occurred. Additional poles are retrofitted depending upon the incident; for example, five poles in each direction are retrofitted in response to eagle mortalities and multiple spans may be marked in response to bird collisions in areas of suitable habitat. Although Rocky Mountain Power is not required to retrofit poles in response to nonprotected wildlife incidents, existing policies encourage retrofits as appropriate to prevent future outages.

As part of the WPP, Rocky Mountain Power will implement additional remedial actions to address wildlife incidents including nonprotected birds and other wildlife in the FHCA. The mechanism for these remedial actions would be similar to the current remedial actions taken in response to protected bird incidents under the APP. Rocky Mountain Power proposes to, at a minimum, retrofit the pole where the wildlife incident occurred, or is suspected to have occurred, to prevent the event from recurring at that location. Retrofitting a pole involves bringing the pole into compliance with Rocky Mountain Power's avian-safe construction design standards described above. Applicable policies and guidance documents will be developed to support implementation of this activity. For the FHCA, planned rebuild work on distribution and transmission circuits will address most areas where wildlife incidents occur, thereby not warranting separate action. However, if a wildlife incident occurs on a pole within the FHCA that is not otherwise identified for remedial action, it will be retrofitted to prevent further wildlife contacts. Data from the past nine years has indicated an average of 110 wildlife-caused outages per year in the FHCA. Assuming that the majority of poles within the FHCA will be addressed through other projects, it is estimated that 10% of wildlife-caused outages in the FHCA may require additional work.

Proactive Actions. Rocky Mountain Power also plans to implement new proactive measures to address the potential for wildlife incidents. Such measures focus on (a) nest management, (b) substations, and (c) line elements.

Nest Management. Under the existing APP, considerable work is done to manage bird nests. During line inspections and operational activities throughout Rocky Mountain Power's service territory, field personnel identify nests on facilities that may have the potential to result in fires, outages and other operational problems. These nests are categorized as "problem nests" and are documented and managed as appropriate through coordination with Rocky Mountain Power's environmental services department and as authorized under state and federal permits. Proactive nest management may include removing or relocating the nest, discouraging birds from nesting in areas on structures that may lead to operational issues, providing an alternative nest site (nest platform), trimming nest material, installing an avian guard, and/or ensuring that surrounding utility facilities are avian-safe. Active nests (those with eggs or young) of species listed under MBTA are protected and management activities may only be implemented in accordance with Rocky Mountain Power's Migratory Bird Special Purpose Utility Permit (issued by USFWS) and applicable state permits. In the case of an emergency situation (circumstance where a bird nest poses impending danger of fire, safety risk to crew, avian electrocution, or threat to human life or property that requires immediate action), Rocky Mountain Power crews will take immediate, appropriate nest management actions, in consultation with environmental services, who will communicate this with the regulatory agencies. Nest management activities are reported annually to federal and state wildlife agencies in accordance to permit requirements. Nest management that is needed for eagles or federally listed threatened or endangered species requires additional permitting and agency coordination before proceeding; the need for this type of permitting is infrequent, can take a significant amount of time to obtain (months to years) and typically will have associated stipulations for mitigation and monitoring.

As part of the WPP, environmental services proposes to implement more proactive measures regarding nest maintenance and management within the FHCA. These actions are intended to reduce wildfire risk directly related to nests on Rocky Mountain Power infrastructure and provide nesting opportunities on nonenergized sites away from lines. Such actions may include the following

- Increased maintenance of Rocky Mountain Power-owned nest platforms on or near energized poles. First, a nest platform inventory may be conducted within the FHCA to verify locations, status/activity and prioritize maintenance work. Maintenance work would be designed to reduce wildfire risk. For example, some species, particularly osprey and ravens, bring baling twine, metal, wire or other rubbish to their nests. Removing these objects from nests can reduce the volume of materials that could be a potential fire ignition source if there was contact with electrical equipment. To adhere to avian regulations and permits, maintenance work would be done when nests are inactive and for species that are covered under existing Rocky Mountain Power permits (e.g., migratory birds; non-eagles, nonendangered or threatened species). Based on the current number of "problem" nests documented in WITS in Utah since 2015, the company estimates that 27 nests within the FHCA will need to be maintained annually.
- Installation of nest platforms and nest boxes. Rocky Mountain Power plans to install additional nest platforms where appropriate in the FHCA, to facilitate removal of problem nests from Rocky Mountain Power facilities. In areas where dead snags along utility rights-of-way in the FHCA may be fire hazards, Rocky Mountain Power may remove these trees as part of vegetation management activities. Because nesting cavities located in such dead snags may be limited and important to cavity-nesting species, Rocky Mountain Power proposes to partner with groups that install nest boxes for American kestrels, screech owls and other cavity nesting birds. Support of these nest box programs would help offset our impact to these species, and would provide alternative nesting sites that are maintained and do not pose a fire risk.

Substations. Under current practices, avian protection devices are installed (or the presence of existing avian protection devices is verified) at substations during routine planned maintenance. Such avian protection devices include covers and/or barriers at equipment locations where there is an increased risk of electrocution (e.g., circuit breaker bushings, substation transformer bushings and arresters, switches, and station service transformers, cutouts and arresters).

As part of the WPP, the company is evaluating whether any wildlife guards could be employed in substations to minimize wildlife contacts.

Lines and Line Elements. Risk assessment surveys are currently conducted as needed to assist with identifying structures for proactive retrofitting efforts. These surveys involve visual inspection of lines, structures, equipment and rights-of way to identify evidence of avian use, mortalities, nests and risk. Circuits and regions are prioritized throughout Rocky Mountain Power's service territory based on avian mortality history, eagle-specific risks and incident trends. Circuit priorities are re-assessed annually to identify current conditions, including availability of suitable avian habitat, avian population shifts, prey base, surrounding land use and proactive retrofitting activity completion status. These prioritizations are reviewed during routine APP meetings with the USFWS. Within prioritized circuits, field risk assessment surveys are conducted to identify high-risk poles and determine appropriate retrofitting needs.

In addition to circuit prioritization, a spatial-based analysis may be conducted to determine focal areas to implement proactive retrofit activities. Spatial-based analysis uses density and heat mapping within ArcGIS to identify high-risk avian environments. Using GIS modeling, the highest risk poles in a specific area may be identified by considering habitat and pole-related variables such as pole configuration, presence of equipment, existing avian protection, and other factors determined to be significant based on existing local data.

In addition to circuit prioritization, a spatial-based analysis may be conducted to determine focal areas to implement proactive retrofit activities. Spatial-based analysis uses density and heat mapping within ArcGIS to identify high-risk avian environments. Using GIS modeling, the highest risk poles in a specific area may be identified by considering habitat and pole-related variables such as pole configuration, presence of equipment, existing avian protection, and other factors determined to be significant based on existing local data.

The planned rebuild work on distribution and transmission circuits in the FHCA, discussed in the system hardening section, will incorporate current best practices to limit wildlife contacts. In particular, use of covered conductor virtually eliminates avian contacts. Consequently, most lines in the FHCA will not require retrofits. Lines which are not being rebuilt, however, will be assessed for retrofitting. The company will coordinate WPP retrofit projects with other long-term planning objectives.

5.3. Other Environmental Considerations

Rocky Mountain Power's wildland fire protection efforts will require coordination with governmental agencies and may also require additional permitting related to trust resources (e.g., cultural, water and biological resources). To facilitate proactive wildland fire protection work and to avoid possible regulatory violations, Rocky Mountain Power's environmental services assesses regulatory requirements and actively coordinates with applicable agencies. This subsection identifies coordination needs, surveys and measures that can be taken to streamline agency authorizations for maintenance work and wildland fire protection activities. In addition, collaborative efforts with external organizations are proposed where such efforts would provide an overall reduced wildfire risk (e.g., fuels reduction, habitat enhancement).

Some wildland fire protection activities may have environmental impacts and necessitate agency coordination or permitting before implementation. These activities may be related but not limited to vegetation management, ground disturbance, access road creation or maintenance, changes to right-of-way boundaries or conditions, seasonal timing of work and potential impacts to threatened/endangered/sensitive species, cultural resources, wetlands or other natural resources. In some cases, proactive measures can be taken to communicate with agencies and resolve potential environmental issues that could arise in future work.

Coordination between environmental services and various other Rocky Mountain Power business units and governmental agencies is common. Some examples of areas requiring such coordination are:

- Access road filling, improvements, rerouting or expansions
- Power line structure modification or replacements
- Ground-disturbing activities
- Activities on public lands
- Wetland and waterway impacts
- Implementation of fire minimization Best Management Practices (BMPs) from the APLIC document Best Management Practices for Electric Utilities in Sage-grouse Habitat, as applicable, in Rocky Mountain Power projects
- Environmental impacts associated with undergrounding power lines
- Seasonal activity buffers and other restrictions to protect nesting birds, sage-grouse leks, big game winter range, winter bald eagle roosts and other sensitive wildlife

- Agency stipulations regarding rare plant or wildlife surveys
- External habitat efforts that promote low growing, fire resilient species and pollinator habitat in rights-of-way
- Any other environmental impacts identified through use of an environmental checklist

Many initiatives require extensive and detailed involvement by environmental services. For example, certain projects, both existing and potential, require biological and cultural review and/or surveys to support implementation. A few possibilities are outlined below:

- **O&M Plan.** Rocky Mountain Power environmental services will continue efforts with federal land management agencies, including the respective state offices of the BLM and USFS, to update (or develop as the case may be) an O&M plan that guides Rocky Mountain Power's maintenance activities on lands managed by the respective agency and streamlines permitting activities. These efforts have been ongoing for several years with the Utah BLM, and such collaboration can be valuable to facilitate wildland fire protection activities. Future iterations may include permit consolidation (master permits) by forest or field office, which would allow for more efficient and timely response to conditions or wildfire threats.
- **Fuel Breaks.** There may be opportunities to use Rocky Mountain Power rights-of-way as fuel breaks. Rocky Mountain Power environmental services may coordinate with state, federal, and other agencies to identify opportunities, challenges and potential requirements.
- **Habitat Enhancements.** Habitats can be managed to reduce the wildfire risk, and there may be partnership opportunities with third parties already conducting habitat enhancement work. Examples include rangewide sage-grouse conservation efforts and state or local efforts, such as Utah's Watershed Restoration Initiative (WRI). The Utah WRI implements habitat conservation projects, including fuels reduction efforts that can limit the frequency and intensity of destructive fires, reduce fire-prone invasive plant species and restore degraded habitats to functioning, fire resilient watersheds. WRI brings together public and private partners to develop and implement projects, leverages matches an average of 5:1 and addresses environmental and cultural resource clearances that would otherwise be challenging for Rocky Mountain Power to conduct on its own. Rocky Mountain Power environmental services may work with WRI to identify existing projects for funding or develop partnerships for projects that include beneficial treatments in Rocky Mountain Power rights-of-way, especially projects located in the FHCA.

- **Pollinator Habitat Conservation.** Pollinator habitat tends to mitigate wildfire risk, because pollinator habitat often includes vegetation more resistant to wildfire ignition and spread. Rocky Mountain Power environmental services may explore opportunities to implement pollinator habitat conservation practices, as appropriate, in Rocky Mountain Power rights-of-way. To this end, Rocky Mountain Power environmental services plans to collaborate with other utilities, agencies and industry groups (e.g., EEI) to identify current best practices for maintaining pollinator habitat, and therefore fire resilient habitat, in utility rights-of-way.

6. Construction Standards

Construction standards have been developed for the use of Rocky Mountain Power personnel and contractors in the construction, operation and maintenance of Rocky Mountain Power's electric distribution facilities. Systemwide construction standards play an important role in the continued expansion of Rocky Mountain Power's facilities, as well as ensuring that modifications to existing facilities are in line with updated industry practices. Standards properly developed and applied accomplish the following objectives:

1. Establish desired design criteria and performance levels
2. Ensure uniform, safe and economical construction practices
3. Provide information on materials and their proper application
4. Minimize engineering and estimating time
5. Provide the basis for automated material and labor determination for estimates and work orders

Each standard is typically re-evaluated within 10 years of its publication date to ensure it is in accordance with current codes and beneficial to Rocky Mountain Power and its customers. As discussed previously, Rocky Mountain Power has identified geographic areas with the greatest wildfire risk, which are designated as in the Fire High Consequence Area (FHCA). After designating the FHCA, the Rocky Mountain Power engineering standards department completed and published construction standards for certain types of equipment that are approved for new construction in the FHCA. In addition, the standards department has identified certain equipment, the use of which is discouraged in the FHCA. Map layers showing the FHCA are available in the company's internal mapping applications as a guide for estimators to determine where to use these construction standards.

General FHCA Applications. Certain equipment has design characteristics that make the equipment less likely to ever be involved in a fire ignition, as compared to alternatives frequently used in the construction of electrical facilities. For example, many traditional fuses are commonly referred to as expulsion fuses because such fuses could emit a shower of sparks if operated. Obviously, the sparks from an expulsion fuse can ignite a wildfire if a fuse operates in an area with dry wildland vegetation. There are, however, alternatives to traditional expulsion fuses. A fuse that does not emit a shower of sparks on operation is commonly referred to as a non-expulsion fuse. Because the non-expulsion fuse does not emit sparks, its use mitigates wildfire risk. Accordingly, the engineering standards department has researched non-expulsion fuses and created a construction standard for using such equipment on Rocky Mountain Power facilities in the FHCA. Other types of equipment have also been evaluated. With respect to distribution structures, two categories of equipment were identified as follows:

- **FHCA Exempt** standards identify equipment that has been designed to mitigate the risk of fires in high fire-threat areas. See Figure 24.
- **FHCA Non-Exempt** standards have been identified as not mitigating the risk of fires in FHCA. In other words, FHCA non-exempt equipment has a greater likelihood of emitting sparks. FHCA-non-exempt standards are marked at the top of the first page with the symbol shown in Figure 25.

(Cal Fire uses the terms "exempt" and "non-exempt" because the use of certain equipment exempts a pole from pole clearing requirements. This terminology has become accepted in the industry, and Rocky Mountain Power has, therefore, used the exempt and non-exempt terms in its construction standards.) There are of course devices that are neither FHCA Exempt nor FHCA Non-Exempt, which may continue to be used in the FHCA as standard design, so long as there is no FHCA Exempt alternative required for such construction. Standards for FHCA Exempt devices are marked with the following symbol:

Figure 24. Symbol for "FHCA Exempt"

To develop these construction standards, Rocky Mountain Power referred to the Cal Fire Power Line Fire Prevention Field Guide (2008 Edition).

In addition to creating construction standards for equipment that mitigates fire risk when used (and is designated as approved for use in the FHCA), work has also been completed to identify certain equipment that increases the risk of wildfire when used. Consequently, standards have been developed to designate equipment that is not allowed for use in the FHCA. Such equipment may continue to be used in normal construction activities outside the FHCA. But the standard for such equipment will be designated as FHCA Non-Exempt and marked at the top of the first page with the following symbol:

Figure 25. Symbol for "FHCA Non-Exempt"

The standards department continues to evaluate and add new devices and construction methods to the FHCA standards regularly as new technologies becomes available.

7. System Hardening

Rocky Mountain Power's electrical infrastructure is engineered, designed and operated in a manner consistent with prudent utility practice, enabling the delivery of safe, reliable power to all customers. When installing new assets, Rocky Mountain Power is committed to incorporating the latest technology and engineered solutions. When conditions warrant, Rocky Mountain Power may engage in strategic system hardening, which means replacing existing assets (or, in some circumstances, modifying existing assets using a new design and additional equipment) to make the assets more resilient. Recognizing the growing risk of wildfire, Rocky Mountain Power proposes to substantially supplement existing asset replacement projects with system hardening programs designed to mitigate specific operational risks associated with wildfire.

System hardening programs are designed in reference to the equipment on the electrical network that could be involved in the ignition of a wildfire. In general, system hardening programs attempt to reduce the occurrence of events involving the emission of sparks (or other forms of heat) from electrical facilities. No single program mitigates all wildfire risk related to all types of equipment. Individual programs address different factors, different circumstances and different geographic areas. Each program described below, however, shares the common objective of reducing overall wildfire risk associated with the design and type of equipment used to construct electrical facilities. In prioritizing particular design or equipment elements, these programs can also consider environmental factors impacting the magnitude of a wildfire. Dry and windy conditions pose the greatest degree of risk. Consequently, system hardening programs may specifically attempt to reduce the potential of an ignition event when it is dry and windy, by looking at equipment that is more susceptible to failure or contact with foreign objects when it is dry and windy.

It must be emphasized, however, that system hardening cannot prevent all ignitions, no matter how much is invested in the electrical network. Equipment does not always work perfectly and, even when manufactured and maintained properly, can fail; in addition, there are external forces and factors impacting equipment, including from third parties and natural conditions. Therefore, Rocky Mountain Power cannot guarantee that a spark or heat coming from equipment owned and operated by Rocky Mountain Power will never ignite a wildfire. Instead, Rocky Mountain Power seeks to reduce the potential of an ignition associated with any electrical equipment. To this end, Rocky Mountain Power plans to make substantial investments with targeted system hardening programs.

For clarity, it is worth noting that system hardening is a concept closely related to other wildland fire protection strategies discussed in this plan. Rocky Mountain Power is committed to use the best designs and technologies when completing corrections of identified conditions, as discussed in the prior section on inspections and corrections, and when constructing new line extensions, which is addressed in the next section. Also along these lines, Rocky Mountain Power developed new design standards applicable to new construction in areas of elevated wildfire risk, described in the construction standards section. The idea of “system hardening” applies in these contexts, as Rocky Mountain Power certainly plans for new construction to be “hardened” against wildfire risk. This particular section on system hardening, however, is geared toward specific programs aimed at making existing facilities more resistant to wildfire, even though those existing facilities are fully functional and do not require any corrective work under current utility best practices.

7.1. FHCA Line Rebuild Program

As a central part of this wildland fire protection plan, Rocky Mountain Power is planning to rebuild a number of selected power lines. The rebuild program is well above and beyond standard utility practice. It is not typical to tear down and rebuild an entire line. Instead, particular equipment components are replaced on an as-needed basis. Likewise, a particular pole might be replaced if necessary. Thus, over time, particular segments of a line may be “rebuilt” as part of an ongoing process of smaller, individual capital improvements at specific pole locations. This approach, under normal circumstances, is typically the most cost effective way to provide safe and reliable electric service.

Because of the heightened risk of a catastrophic wildfire in the FHCA, Rocky Mountain Power is spearheading a new program to comprehensively rebuild selected lines. The rebuild program will involve new construction from the ground up and for the entire length of a selected segment of a line, including the installation of new conductor and new poles. In other words, the end result of a project will be a brand new line, as if there had not previously been a line at that location. New construction of an entire line is expensive. Rocky Mountain Power proposes to make this investment because a comprehensive approach will be the most efficient way to upgrade all equipment on a line at one time and make all components of the entire line more resilient against wildfire. It is also the most efficient way to make a transition to covered conductor, which is discussed in greater detail below.

The company used different criteria to determine which lines are included within the line rebuild program. First, because of the heightened risk in the FHCA, all lines included in the rebuild program are located at least partially in the FHCA. Certain segments of a rebuild might extend outside the FHCA, based on the location of substations or protective devices. In general, however, the vast majority of rebuild is in the FHCA. Second, the company evaluated the average age of poles on the line. If the average age of poles was above 45 years of age, the line was included in the rebuild program. Third, even if the average age of poles was less than 45 years of age, particular lines were hand-selected for rebuild based on local knowledge of the electrical infrastructure.

In using average pole age as the objective criteria, we must emphasize that pole age of an individual pole, alone, does not necessarily have a direct correlation to risk; an old pole may be perfectly strong, whereas a younger pole may suffer decay because of specific conditions at that pole location (i.e., soil, drainage, insects, etc.). In other words, continued use of an older pole (i.e., even a pole much older than 45 years of age) is appropriate for safe and reliable service unless there is an observable defect in the pole. And the normal industry standard is to replace a pole only when that particular pole manifests a certain degree of observable weakness. Nonetheless, the heightened risk of wildfire warrants selected application of a more aggressive approach, and average pole age is an appropriate criteria to determine which segments of line are the highest priority candidates for a rebuild. When an entire group of assets is assessed from the perspective of asset age (i.e., a segment of line, with all of its components), there is some direct relationship with risk. As the average age of assets on a line increases over time, the probability that some portion of equipment will fail increases to some degree. Pole age is a data point maintained by the company, and the average age of poles is highly indicative of the age of all of the assets on the line (especially in relative terms to other lines). Consequently, the company has used average pole age as the objective measure by which to qualify line segments in the FHCA for the rebuild program.

After identifying line segments based on average pole age, the company also added other line segments of special concern. As discussed in the risk assessment section above, the FHCA is a geographic area, reflecting computer simulation modeling of wildfire spread and its impacts on people and property. That larger risk assessment does not necessarily account for the unique circumstances of a specific power line at any given location. Because of topography, some power lines have certain operational challenges that other lines do not have. For example, some lines are simply easier to patrol because they run parallel to an established roadway. Other lines, however, might have been constructed up a steep mountain slope. Thus, certain lines were added to the rebuild project because of their unique characteristics, assessed in context with the immediately surrounding landscape. In general, an FHCA line traversing dense, tall vegetation and crossing exposed ridges with frequent high winds was considered as a rebuild candidate, even if the average age of poles was less than 45 years of age.

Covered Conductor. Historically, the vast majority of high voltage power lines in the United States – and in Rocky Mountain Power's service territory – were installed with bare overhead conductor. As the name "bare" suggests, the wire is all-metal and exposed to the air. For purposes of wildfire mitigation, a new conductor design has emerged as the preferred approach. Most of the projects in the FHCA Line Rebuild Program will involve the installation of covered conductor. Covered conductor is also frequently called insulated conductor or insulated wire. Sometimes, with some variations in products, it is also called spacer cable, aerial cable, or tree cable.

The dominant characteristic of covered conductor is that the metal conductor which actually carries electricity is sheathed in a plastic covering. As a comparison for the lay person, covered conductor is like an extension power cord that you might use in your garage. The plastic coating provides insulation for the energized metal conductor inside the plastic coating. To be clear, covered conductor is not insulated enough for people to directly handle an energized high voltage power line (as discussed below). But the principle is the same. The plastic sheathing provides an insulating effect. It is this insulating effect which reduced the risk of wildfire, by greatly reducing the number of faults that would have occurred had bare conductor been used.

Variations in covered conductor products have been used in the industry for decades. Due to many operating constraints, however, use of covered conductor tended to be limited to locations with extremely dense vegetation where traditional vegetation management was not feasible or efficient. Recent technological developments, however, have markedly improved covered conductor products, reducing the operating constraints historically associated with the design. These advances have improved the durability of the project and reduced the impact of thermal insulation (i.e. because bare wires are exposed to air, bare wires can cool easier). There are still logistical challenges with covered conductor. Above all, the wire is heavier, especially when carrying snow or ice in the cold Utah weather, meaning that more and/or stronger poles are required when using covered conductor. And the product itself is more expensive than bare conductor.

The wildfire mitigation benefits of covered conductor are significant. As discussed in the risk assessment section, a disruption on the electrical network, a fault, can result in emission of spark or heat that could be a potential source of ignition. Covered conductor greatly reduces the potential of many kinds of faults. For example, contact from object is major category of real-world faults which can cause a spark. Whether it is a tree branch falling into a line or a Mylar balloon carried by the wind drifting into a line, contact from those objects with energized bare conductor causes the emission of sparks. If those same objects contact covered conductor, the wire is insulated enough that there are no sparks. Likewise, many equipment failures are a wildfire risk because the equipment failure then allows a bare conductor to contact a grounded object. Consequently, covered conductor greatly reduces the risk of ignition associated with most types of equipment failure. For example, if a crossarm breaks, the wire held up by the crossarm often falls to the ground (or low and out of position, so that the wire might be contacting vegetation on the ground or the pole itself). In those circumstances, a bare conductor can emit sparks (or heat) that can cause an ignition. The use of covered conductor, in those exact same circumstances, would almost certainly not lead to an ignition, because the insulation around the wire is sufficient enough to prevent any sparks and limit energy flow, even when there is contact with an object.

Covered conductor is especially well-suited to reduce the occurrence of faults reasonably linked with the worst wildfire events. Dry and windy conditions pose the greatest wildfire risks. Wind, in particular, is the driving force behind catastrophic wildfire spread. At the same time, wind has distinct and negative impacts on a power line. The wind blows objects into lines; a strong wind can cause equipment failure; and even parallel lines slapping in the wind can cause sparks. Covered conductor specifically reduces the potential of a catastrophic ignition event, because covered conductor is especially effective at limiting the kinds of faults that occur when it is windy. Taken together, these substantial benefits warrant the use of covered conductor in areas with a high wildfire risk.

While the wildfire mitigation benefits are substantial, certain disadvantages with covered conductor need to be addressed as well. In addition to the added expense and operational limitations mentioned above, the benefits that covered conductor provide also lead to a unique challenge. With bare conductor, the utility usually learns about an event relatively quickly, because a significant or persistent fault typically results in an outage. When an outage is reported, the utility can generally patrol the line to identify any obvious structural problems. A bare conductor on the ground may sometimes still be energized. If the contact with ground (or vegetation with a path to ground) mimics the use of electricity by downstream customers, the protection equipment on the line may not activate to open a breaker and de-energize the line. Nonetheless, a high impendence fault tends to be temporary and will usually lead to an outage in a relatively short term. In sum, a displaced bare conductor will generally be spotted and corrected within a relatively short timeframe.

Covered conductor works differently. Because the covered conductor is designed to avoid a fault, it is also likely to remain energized, even if not properly attached to a pole. From a wildfire mitigation perspective, not learning about an event is a sign that covered conductor is working as intended (i.e. a fire cannot have started if no sparks were emitted). But the ability for covered conductor to avoid an electrical fault and stay energized implicates a separate set of concerns. If a tree branch momentarily touches a covered conductor, it is not an issue, because the line simply continues to operate as intended. But when the covered conductor is physically displaced from its designed position, it can be difficult to identify. Taking again the example of a broken crossarm, a covered conductor hanging a few feet off the ground, perhaps even contacting tall, dry grass or lying across Gambel oak, will almost certainly not experience a fault right away, which is a good outcome. In that case, an ignition will not occur. A downed or low-hanging line is always, however, a safety hazard. Because the insulation on the covered conductor works to prevent an outage in a situation like this, the line remains energized. As a fundamental rule, a person should never touch or handle any energized high voltage line, even if it is insulated. Touching an insulated conductor is certainly less dangerous than touching a bare conductor, and incidental contact with a covered conductor should be harmless. But there are still risks of electrical contact injury to any person touching the wire. The insulating effect of the sheathing on the covered conductor in not rated to prevent the flow of electricity to a person in direct contact with the ground, and a person touching a covered conductor could still be seriously injured. If the wire has actually broken (i.e., because a tree fell into the line), there is a risk of contacting the two exposed ends.

In sum, at a very basic level, covered conductor is safer overall compared to bare conductor. Not only does covered conductor reduce the risk of wildfire, it is less dangerous to contact a covered conductor compared to a similar voltage bare conductor. Combined with the substantial wildfire mitigation benefits, covered conductor is the preferred design for rebuild projects. There are, however, unique challenges implicated in making it harder to spot a low-hanging or downed line.

Rocky Mountain Power also evaluated the costs and benefits of underground design for the rebuild projects. The potential wildfire mitigation benefits are undeniable. While an underground design does not completely eliminate every ignition potential (i.e. because of above-ground junctions), it is the most effective design to most dramatically reduce the risk of any utility-related ignition. Unfortunately, because of cost and operational constraints, the functional realities of underground construction prevent widespread application as a wildfire mitigation strategy. Nonetheless, Rocky Mountain Power is using an underground design as part of the rebuild projects when functional and cost-effective. Through the design process, each individual rebuild project is assessed to determine whether sections of the rebuild should be completed with underground construction. As a practical matter, the great majority of the rebuilds will be covered conductor. This outcome is consistent with emerging best practices. Utilities in geographic areas with extreme wildfire risk, including in California and Australia, are trending heavily towards use of covered conductor, with limited applications of underground construction where appropriate. Indeed, sourcing material for the planned projects is challenging because of the industry trend towards use of covered conductor as a primary wildfire mitigation strategy. On a related note, the company remains willing to consider additional underground applications. Some communities and landowners may prefer, for aesthetic reasons, to pursue a higher cost underground alternative. Consistent with controlling electric service regulations, Rocky Mountain Power will work with communities or individual landowners who are willing to pay the incremental cost and obtain the necessary legal entitlements for underground construction, if covered conductor is the least cost option for a rebuild project.

7.2. Pole Replacement Program

As indicated above, all poles on a rebuilt line will be replaced as part of a rebuild program. The intent of the rebuild program is to comprehensively bring the line to a new condition. (In addition, the conversion to covered conductor often necessitates pole replacement anyway.) For lines in the FHCA which are not being rebuilt, Rocky Mountain Power is planning to replace selected poles through a pole replacement program. The company will prioritize poles for replacement based on pole age, and all poles in the FHCA over 45 years of age will be selectively replaced as part of the program.

In some applications, Rocky Mountain Power may replace a wooden pole with a steel or composite pole. In most applications, however, the company will continue to use wooden poles. A steel pole is obviously stronger than a wooden pole, meaning that it is generally less likely, in the same period of time, to fail. Because it is not flammable, a steel pole is also generally better at withstanding a wildfire burning through the area in which it is located without damage to the pole itself. A wooden pole, however, tends to perform extremely well, especially in Utah's arid climate. With that proven performance, a wood pole tends to be more cost effective in most standard applications. A steel pole will be used when greater strength is required. To mitigate against damage to a wooden pole, Rocky Mountain Power is investing in fireproof mesh wrapping to protect selected at-risk poles (see immediately below). In sum, the company determined that for most applications wooden poles are generally more cost-effective.

7.3. Fireproof Mesh Wrapping

Many wooden poles will be wrapped as part of Rocky Mountain Power's efforts to protect its own assets. The vast majority of wildfires do not have a utility-related ignition. Wildfires can burn through the area where an electric power line is located and cause massive damage to the line. Accordingly, Rocky Mountain Power plans to wrap wooden poles with a protective material. The fireproof mesh wrapping is intumescent, meaning that it swells in the event of a fire. That swelling protects the underlying wood. The manufacturers have tested the material at labs to demonstrate the material's effectiveness at protecting wooden poles from fire damage.

Wooden poles will be selected for wrapping based on perceivable wildfire threat to the pole. In essence, wooden poles in close proximity to at-risk fuels will be prioritized for treatment. There are three main categories of wooden poles that will receive wrapping treatment. First, many wooden poles installed as part of the FHCA Line Rebuild Program will be treated with fireproof mesh wrapping. After spending so much to rebuild a line, the company has a strong desire to protect the investment. Second, some existing wood poles in the FHCA will be wrapped on an as-needed. Poles that are relatively young, structurally sound, and have no outstanding observed maintenance needs affecting the strength of the pole fall into this category. Third, if a pole has experienced a history of fire damage from third parties performing controlled burns, fire wrap may be considered as an alternative.

7.4. Relays for Advanced System Protection Program

Rocky Mountain Power plans to replace electro-mechanical relays with microprocessor relays. Microprocessor relays provide multiple wildfire mitigation benefits. Microprocessor relays are able to exercise programmed functions much faster than an electro-mechanical relay. Above all, the faster relay limits the length and magnitude of fault events. After a fault occurs, energy is released, posing a risk of ignition, until the fault is cleared. Reducing the duration of a fault event reduces the risk that the fault might result in a fire. Microprocessor relays also allow for greater customization to address environmental conditions through a variety of settings, and are better able to incorporate complex logic to execute specific operations. These functional features allow for the company to use more refined settings for application during periods of greater wildfire risk. Finally, in contrast to electro-mechanical relays, microprocessor relays retain event logs that provide data for fault location and later analysis. In certain circumstances, this information can help the company locate and correct a condition prior to the condition leading to a more serious event. At a minimum, such information facilitates better knowledge of the network, possibly shaping future mitigation strategies. As part of replacing an electro-mechanical relay, the associated circuit breaker may also be replaced, as appropriate to facilitate the functionality of a microprocessor relay.

7.5. Non-Expulsion Fuse Installation Program

Rocky Mountain Power is systematically replacing all expulsion fuses in the FHCA with comparable non-expulsion devices. A standard expulsion fuse, industry standard for many decades, could emit a shower of sparks during operation. A fuse is a safety device that allows a release of energy to protect the line from too much current in the event of a fault on the line. After the fuse operates, the circuit is opened, and the line is de-energized. Because of the obvious wildfire risk associated with such an operation, comparable devices were developed to eliminate the sparks expelled to the ground. In essence, energy is still redirected through a charge; but the charge is blown into a bed of sand that is fully enclosed in the equipment itself. Thus, this new type of fuse has earned the name of "non-expulsion fuse," because it does not expel sparks towards the ground. A non-expulsion fuse offers undeniable wildfire mitigation benefits compared to an expulsion fuse. The only downside is cost, because a non-expulsion fuse costs many more times as much as a standard expulsion fuse. Because it effectively eliminates a definite risk of ignition, the company has determined that non-expulsion fuses are a cost justified wildfire mitigation strategy in the FHCA. Similarly, expulsion lightning arresters when exposed to an overvoltage condition, typically caused by lightning, will ignite a small charge that could expel a spark towards the ground. The company is in the process of replacing these devices with non-expulsion equivalents.

Fuse replacement also implicates coordination concerns. To enable effective trouble-shooting, fuses on downstream sections of a line need to be fuse coordinated with upstream devices. As a result, an individual expulsion fuse cannot simply be replaced with a non-expulsion device in isolation. Recognizing fuse coordination concerns, Rocky Mountain Power is planning to complete fuse replacements on a line-by-line basis. Because the FHCA is a geographic area, some sections of a line can be in the FHCA while other sections of the same line are not. For purposes of fuse coordination, the company will fuse coordinate all downstream sections of a line with any portion of such line in the FHCA.

8. New Construction

As demonstrated throughout this wildland fire protection plan, most wildland fire protection strategies focus on existing facilities. The electric system is not, however, static. As communities face growing risks of wildfire, electric utilities need to also consider mitigation strategies that address new and modified facilities. Indeed, the wildfire risk is driven largely by human development. While significant wildfires in remote wilderness areas are serious events with both positive and negative ecological consequences, the wildfires that cause the greatest harm to people and property are those that occur nearer to denser areas of human development. Above all, as discussed in the risk assessment section above, human development in the wildland urban interface – the area in which homes and other development are situated near expanses of predominantly wildland vegetation or incorporate sections of wildland vegetation in their landscaping plans – is particularly susceptible to wildfire. The relatively dense populations and relatively expensive structures in these wildland-urban interface areas pose a unique wildfire risk. And the electrical network plays a role, because the electrical network follows and facilitates the growth and expansion of new buildings where people live and work. From a wildfire perspective, the popularity of underground facilities, driven mostly by aesthetic concerns, significantly mitigates the wildfire risk associated with electric service (despite also increasing some maintenance and reliability concerns). At the same time, underground facilities tend to be much more expensive than traditional overhead construction. In any case, serving load growth in and around the wildland urban interface should factor in a comprehensive wildfire mitigation strategy.

The system of electrical facilities owned and operated by Rocky Mountain Power can be expanded in multiple ways. New construction on the transmission network is typically planned, designed and constructed by Rocky Mountain Power from initiation to end of any project. With respect to distribution lines, expansion of the electrical network is typically driven by customer demand. In general, these expansions are commonly referred to as “line extensions,” because power lines are constructed to extend service to a new location, based on the application made by an applicant.

8.1. Line Extensions

Electric Service Regulation No. 12 govern the process by which line extensions are made. The obligation to serve all customers, on fair terms, is a core principle for regulated electric utilities and is embedded in Regulation No. 12. Along these lines, any wildfire mitigation strategy must be consistent with those rules and regulations.

Right-of-Way – Route Selection. Consistent with Regulation 12 Section (1)(m), Rocky Mountain Power selects the route for a proposed Line Extension. Rocky Mountain Power has to consider a number of factors in selecting the optimal route. The factors include physical construction constraints in topography or soil type, physical access for both construction and long-term maintenance, obtaining the lowest cost to the applicant, and efficiency considerations related to future connections. In some cases, the optimal path is clear. Not surprisingly, following the path of an existing road can often be a sensible approach. In other cases, the optimal path may be less than clear. In some situations, the applicant may have other priorities that support a particular path. In consideration of the underlying principle to provide service on fair terms and the goal of providing excellent customer service, customer preference is factored in the analysis, including a desire to accomplish the lowest cost alternative for the customer.

Another factor in choosing the route for a line extension is the practical need to obtain the necessary legal entitlements for the right-of-way. Under Regulation 12 Section (1)(m), the applicant is responsible for providing Rocky Mountain Power with standard easement rights sufficient to construct and maintain the new facilities. In some situations, the applicant will need to obtain easement rights from a neighboring landowner. This reality will often implicate a need for Rocky Mountain Power to cooperate with the customer on selecting a secondary route alternative, if the applicant is unable, after reasonable efforts, to obtain the easement rights necessary for the preferred path. In those circumstances, Rocky Mountain Power will work with the applicant to identify a secondary route, if feasible, to enable completion of the line extension.

In all cases, an estimator considers local, site-specific conditions. To mitigate the wildfire risk associated with new construction, Rocky Mountain Power estimators will be factoring greater weight on the wildfire risk in selecting the preferred route for a line extension. Because of the impact of fuels, this factor is given more weight in areas with wildland vegetation. To this end, estimators are encouraged to favor routes that have good access, which is valuable not only for regular maintenance but also for spotting and suppressing a fire. Estimators are also encouraged to favor routes that traverse areas with less wildland vegetation (e.g., irrigated areas). All other factors must still be considered, including the total end cost to the customer. The mitigation goal is to make wildfire risk an issue that is properly factored into the route selection process, especially in areas of greater relative risk. Rocky Mountain Power estimators are encouraged to be aware of the wildfire risk associated with any particular route, especially when designing new construction in the FHCA.

Right-of-Way – Pre-Construction Clearing. Again under Regulation 12 Section (1)(m), the applicant is required to make the right-of-way ready for construction. In addition to any costs associated with obtaining the necessary easements, there are some construction costs related to physically preparing the right-of-way for installation. For example, if a right-of-way has to be graded to allow vehicle access, such a cost is appropriately borne by the applicant. If a tree has to be removed to clear way for the installation of a pole, the cost to remove the tree is appropriately charged to the applicant. Likewise, any trees that would immediately implicate the minimum clearance specifications set by Rocky Mountain Power vegetation management must be pruned or removed before construction. Thorough and effective pre-construction clearing significantly aids the efforts of Rocky Mountain Power vegetation management in maintaining clearances through subsequent cycles. Furthermore, any high risk trees that could fall and strike the new line should be evaluated for removal before any construction. Estimators are encouraged to coordinate with vegetation management and to strictly enforce existing requirements for making the right-of-way ready for construction.

Rocky Mountain Power continues to consider how the existing requirements to ready the right-of-way might be further engaged to promote wildfire mitigation. In areas of elevated wildfire risk, preparing a right-of-way to be more resilient to the wildfire risk is arguably part of "preparation or clearing of land." for example, trees that will grow to violate clearance specifications could be removed as part of pre-construction clearing, even if they do not implicate minimum clearance specifications at the time of construction. In addition, trees that are tall enough, or will grow tall enough, to fall and strike the line should be removed. These more aggressive tactics may not be appropriate for every line extension; estimators, in consultation with company foresters, will evaluate such options on a case by case basis.

Facility Design – FHCA Exempt Design Standards. The use of FHCA Exempt equipment is required on line extensions in the FHCA. (See the construction standards section above.) Such requirements may include the use of covered conductor. There is, however, a potential exception for the use of non-expulsion fuses that have an FHCA Exempt design standard. It is necessary to maintain downstream fuse coordination on any power line. Estimators will only use FHCA Exempt fuses on the circuits that have been coordinated with FHCA Exempt fuses. If a circuit has not been coordinated with FHCA Exempt fuses, estimators will use normal T-fuses.

When a line extension is completed in an area of heightened wildfire risk, the facilities should be designed to minimize the risk of ignition. Because of the wildfire risk, the company is making many investments in wildfire mitigation programs that involve replacing working equipment. Completing the initial construction with FHCA Exempt equipment removes any future need to replace such equipment as part of a costly after-the-fact mitigation program. While use of FHCA Exempt equipment is required only in the FHCA, estimators are encouraged to use FHCA Exempt equipment outside the FHCA if local site conditions (i.e. dense wildland vegetation) warrant such use. (Again, it is necessary to maintain proper fuse coordination, so any use of FHCA Exempt fuses will likely be used in conjunction with circuits on the border of the FHCA or on spurs serving a remote location in a wildland area, such as a tap line serving a remote, wooded canyon.)

Facility Design – Span Width. New construction on distribution lines in the FHCA will require urban ruling span. Greater span lengths between poles can reduce construction costs. But shorter span lengths decrease the potential for excessive sag and sway, which can result in phase-to-phase faults on a line. Phase-to-phase faults can result in arcing, which could potentially lead to a fire ignition. Construction using urban ruling span results in substantially shorter span lengths compared to rural ruling span. Traditionally, many areas of elevated wildfire risk would qualify as "rural," and so greater span lengths have been approved in such areas. In areas of the greatest wildfire risk, however, Rocky Mountain Power has determined that the extra construction cost to decrease span lengths is warranted. Accordingly, Rocky Mountain Power is reducing the span lengths between poles in the FHCA by requiring the use of urban ruling span. In addition, estimators consider using urban ruling span on new construction outside the FHCA, when local site conditions indicate an elevated wildfire risk on the particular route selected for the new distribution line.

Facility Design – Underground Construction. The basic design decision of whether to use standard bare overhead wire, some variant of covered conductor, or underground construction has significant implications, for both construction cost to the applicant and long-term wildfire mitigation for the utility. Unless a local ordinance requires underground construction, a line extension traditionally used a bare conductor overhead design. If the applicant is willing to pay the additional cost for an underground construction, an applicant may request underground installation. In certain circumstances, underground design may be required, and estimators consider the benefits of underground installation in areas with wildland vegetation. Because of the dramatic increase in cost, however, an applicant is not typically required to pay for underground construction. Consistent with the other treatments in wildland areas, it is more common to require use of covered conductor and other FHCA exempt equipment in areas of elevated wildland fire risk. Rocky Mountain Power will continue to consider whether more frequent use of underground installation is warranted in rural, wildland areas.

9. Situational Awareness

Situational awareness involves knowledge of the conditions that impact the potential for wildfire ignition and spread. Increasing its situational awareness of such conditions helps an electric utility respond to local conditions and minimize the wildfire risk by making mitigation strategies more effective.

Rocky Mountain Power obtains data regarding local conditions from many sources and uses the data to adjust its operations. Local weather data is the main input. For example, as discussed above, Rocky Mountain Power will adjust reclosing operations based on fire weather forecasts published by government agencies. Above all, the program for de-energizing a power lines, discussed below, is heavily dependent on situational awareness.

Weather Consultants. To improve its access to localized fire weather forecasts, the company has engaged an external weather forecasting expert, Western Weather, to provide Rocky Mountain with daily forecasts for key areas in the FHCA. As discussed in greater detail below, Western Weather may also be called upon to provide real-time weather consulting. Rocky Mountain Power has also engaged experts in the Department of Atmospheric Sciences at the University of Utah to better understand weather metrics associated with wildfire risk, specifically in context with Utah's climate.

Weather Stations. Rocky Mountain Power continues to evaluate the need for additional micro weather data in areas with a high risk of wildfires that could threaten the public and property. In 2019, Rocky Mountain Power installed 11 weather stations on transmission and distribution assets. The company plans to install 25 additional weather stations, to obtain more precise local weather data in the FHCA and Public Safety Power Shutoff (PSPS) areas outlined in Section 10.3. Among other applications, the weather data is used to help determine when to implement an Emergency Operation Center.

High-Definition Cameras. While prevention is always the best mitigation, Rocky Mountain Power is also exploring the effectiveness of high-definition cameras in helping suppress wildfires before they get out of control. Rocky Mountain Power is partnering with Alert Wildfire Systems to install 14 cameras on existing wireless broadband towers. The primary purpose for installing cameras on the Alert Wildfire network is to detect a new plume of smoke at the earliest time possible, to facilitate rapid and effective suppression responses by the appropriate suppression agencies. This technology reflects great potential for minimizing the impact of an ignition, especially in remote areas where a wildfire can often grow out of control before being spotted by people. Cameras at each location will be evaluated after three years of installation to determine whether their locations are proved to be beneficial.

Community Engagement. In understanding wildfire and wildfire risk, Rocky Mountain Power gathers information from community resources. During periods of elevated wildfire conditions and when a wildfire is in progress, the company collaborates with emergency response professionals and local government to help evaluate when and if a power should be de-energized because of an approaching wildfire. Along those lines, the company works with fire suppression experts to protect the electrical network critical infrastructure. Recognizing the long-term benefits of preventative measures, Rocky Mountain Power is committed to supporting programs which decrease the risk of wildfire and/or the impact of wildfire. For example, the company supports educating the public on maintaining defensible space. These common sense measures can both prevent fires and minimize the harm of fires. Defensible space requirements typically address vegetation clearances around power lines, including end of the line service drops to a customer. Compliance with such provisions can help prevent a falling tree branch from bringing down an energized wire. In addition, defensible space works to protect valuable structures from catching fire and burning, thereby minimizing the impact of a wildfire moving through the area. Finally, as discussed in the next section, community engagement is a major focus in Rocky Mountain Power's plan for proactive de-energization.

10. Public Safety Power Shutoff (PSPS)

10.1. Methodology

Rocky Mountain Power may de-energize power lines as a preventative measure during periods of the most extreme wildfire risk. This strategy is sometimes referred to in the industry as "proactive de-energization" – Rocky Mountain Power's initiative is specifically referred to as "Public Safety Power Shutoff" or "PSPS." Traditionally, power lines may be de-energized when an active wildfire is threatening a line. Proactive de-energization implicates a different scenario, contemplating de-energization of lines before there is any fire. The decision to employ PSPS is based on extreme weather conditions, including high wind speeds, high temperatures, low humidity and low fuel moisture content. In essence, PSPS is intended to avoid the potential of an ignition at a time in which such an ignition would be most dangerous. PSPS is a wildfire mitigation strategy of last resort, used to supplement – not replace – all of the various mitigation strategies discussed above. Rocky Mountain Power plans to implement PSPS in only exceptional circumstances. Not only is de-energization inconvenient to customers, de-energization also potentially implicates other public safety concerns. While Rocky Mountain Power cannot guarantee a constant supply of power – and all customers are responsible to make sure that they have backup, contingency plans for when the electric grid is down – Rocky Mountain Power recognizes the practical reality that a reliable energy grid supports a community's ability to respond to a wildfire (i.e., telecommunications, streetlights, water systems, etc.). In balancing these concerns, Rocky Mountain Power makes extraordinary effort to keep the entire grid energized at all times, and PSPS is implemented only when high winds threaten to damage equipment and spark a fire during the most extreme fire conditions.

In 2019, Rocky Mountain Power developed a PSPS plan for Utah. During the summer of 2019, the company met with representatives of local government and the emergency response sector in each of the potentially affected communities to explain the PSPS plan. In addition, Rocky Mountain Power notified customers and held open town hall workshops. Fortunately, due to the relatively mild fire conditions in 2019, Rocky Mountain Power did not have to implement an actual PSPS event. For 2020 and beyond, the company is further evaluating the strengths and weaknesses in the PSPS plan and will make updates and revisions accordingly. In particular, as discussed in the situational awareness section above, Rocky Mountain Power engaged experts in the University of Utah's Department of Atmospheric Sciences, primarily to improve the company's understanding of wildfire weather conditions specific to Utah's climate. Based on that engagement, and additional input from other experts, Rocky Mountain Power expects to further refine the processes it uses to make the ultimate decision of whether to implement a PSPS.

10.2. Methodology for Selecting PSPS Areas

PSPS will only be implemented in geographic areas of the highest wildfire risk. As discussed in the risk assessment section above, Rocky Mountain Power identified Fire High Consequence Areas (FHCA) in its Utah service territory, reflecting areas of elevated wildfire risk. To develop its PSPS plan, Rocky Mountain Power further examined the FHCA, identifying areas of extreme risk due to wildfire to people and property, including where constraints on ingress and egress pose special concerns. Rocky Mountain Power also considered the impact of other wildfire mitigation strategies, discussed throughout this plan, and their effectiveness in eliminating the risk of utility related ignition. As a result of this combined analysis, Rocky Mountain Power identified 10 geographic areas within the FHCA that may be subject to PSPS because of the heightened risk of catastrophic wildfire. Because of population density, nine areas are clustered in the Wasatch Mountains east of Salt Lake City. In such areas, when electrically connected power lines were included, there were over 23,000 customers potentially impacted by a PSPS. Rocky Mountain Power explored alternatives to minimize the impact of a PSPS on such customers. To this end, the company investigated engineering solutions to isolate portions of power lines that reflect substantially less risk of utility-related ignition of a wildfire, meaning that those sections may not need to be de-energized during a PSPS event. For example, if a section of a circuit primarily consists of underground electrical facilities, engineers reviewed whether those underground facilities could be isolated and kept energized during a PSPS. Likewise, if a portion of a circuit was in a high-risk FHCA, but another portion of the circuit was in a relatively low-risk area (i.e., a highly developed area with impervious surfaces and irrigated landscaping), engineers again reviewed whether those lower-risk areas could be isolated and kept in service during a PSPS event. Through this detailed engineering review, Rocky Mountain Power was able to identify substantial sections of the impacted distribution circuits that could be isolated and kept energized during a PSPS event. When the engineering review was done, isolation solutions reduced the impacted customers to approximately 5,700 customers remaining in the resulting PSPS areas, reflecting a greater than 75% reduction.

10.3. Description of PSPS Areas

There is an interactive map on Rocky Mountain Power's website showing the boundaries of the PSPS areas, available on the Public Safety Power Shutoff page at https://www.rockymountainpower.net/outages-safety/wildfire-safety/public-safety-power-shutoff.html. Depending on specific real-time fire weather conditions, such boundaries could shift. For planning purposes, however, any PSPS event would very likely be constrained to the specific area depicted in the interactive map. Such areas are also shown in the figures below.

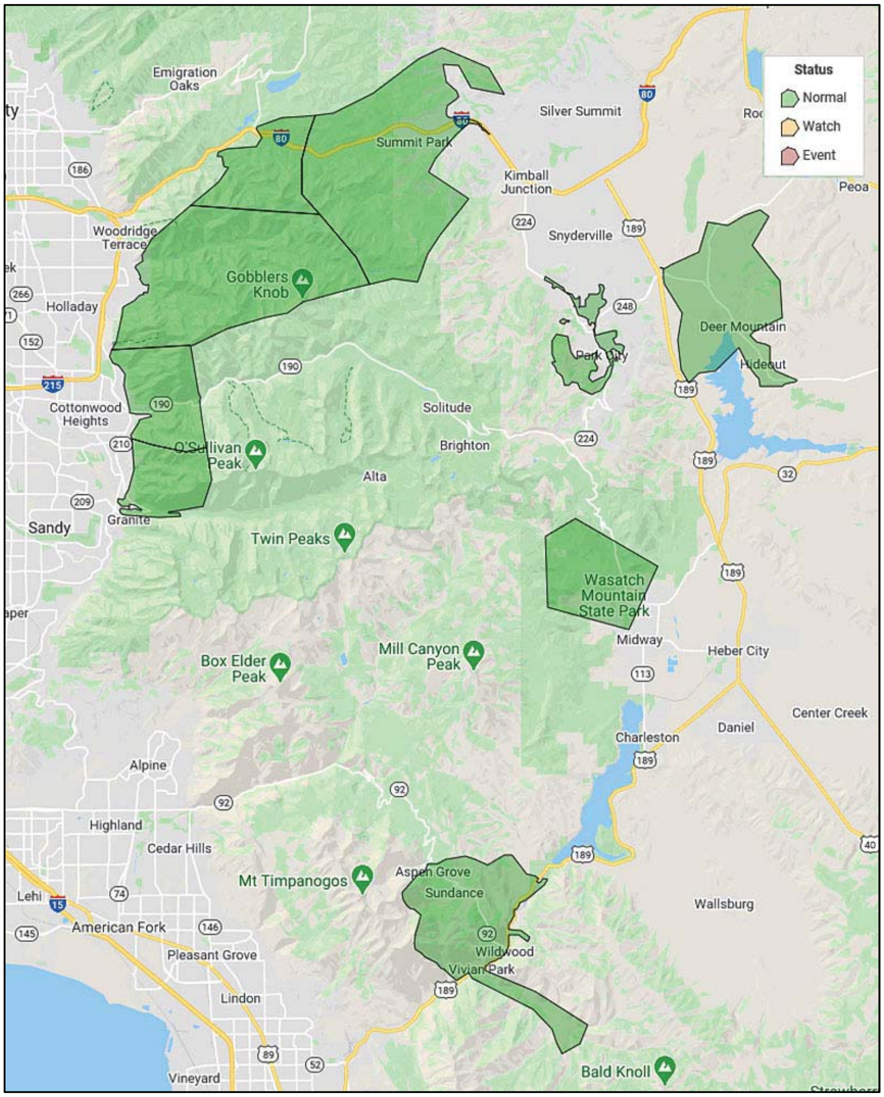

Figure 26. Map of Public Safety Power Shutoff Area in Northern Utah

Little Cottonwood. The Little Cottonwood PSPS focuses on the overhead lines at or near the mouth of Little Cottonwood Canyon.

Figure 27. Map of Little Cottonwood Canyon Public Safety Power Shutoff Area

Big Cottonwood. Similarly, the Big Cottonwood PSPS focuses on the overhead lines at or near the mouth of Big Cottonwood Canyon.

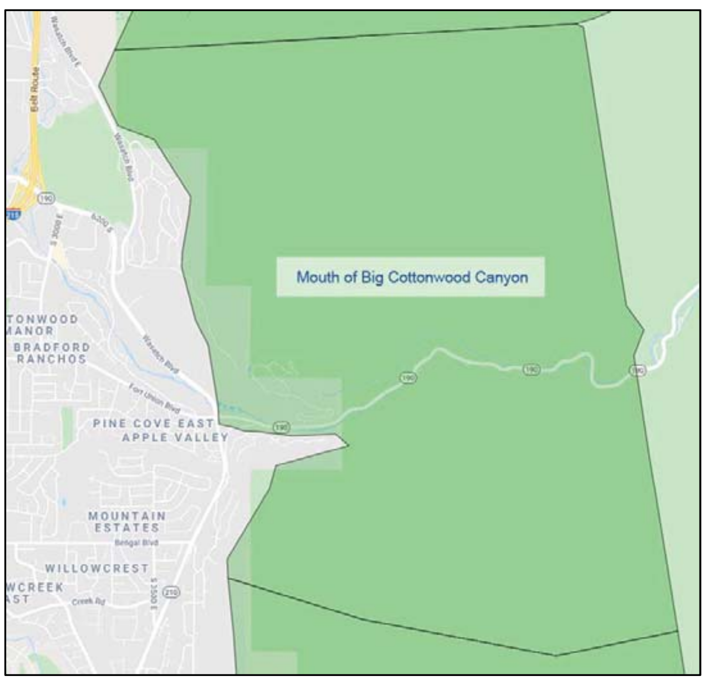

Figure 28. Map of Mouth of Big Cottonwood Canyon Public Safety Power Shutoff Area

Olympus Cove and Millcreek Canyon. This PSPS area includes the properties on the furthest east portions of Olympus Cove that are nearest the wildland areas in the foothills and the entirety of Millcreek Canyon.

Figure 29. Map of Olympus Cove and Millcreek Canyon Public Safety Power Shutoff Area

Mountain Dell. The Mountain Dell PSPS includes the section of the overhead distribution circuit headed east, up Parley's Canyon, from the company's Mountain Dell substation and the overhead distribution line serving the Mt. Aire neighborhood.

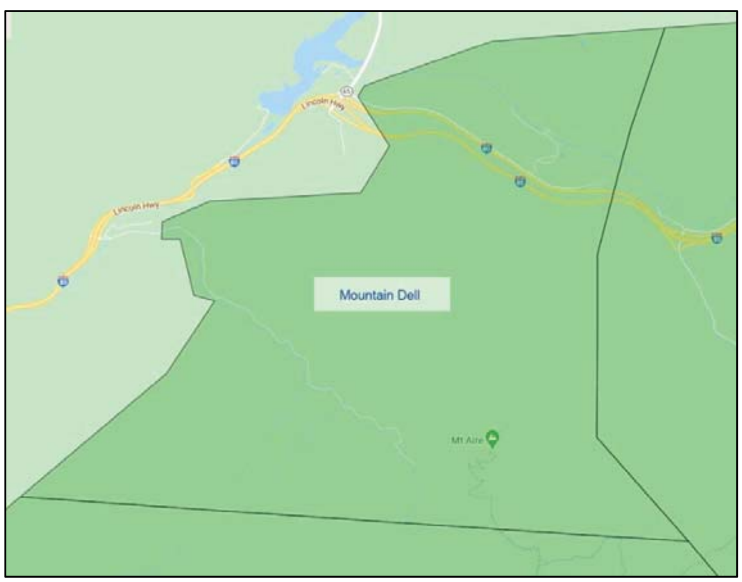

Figure 30. Map of Mountain Dell Public Safety Power Shutoff Area

Summit Park. The Summit Park PSPS includes all of Summit Park, Lamb's Canyon, and the western portion of Jeremy Ranch.

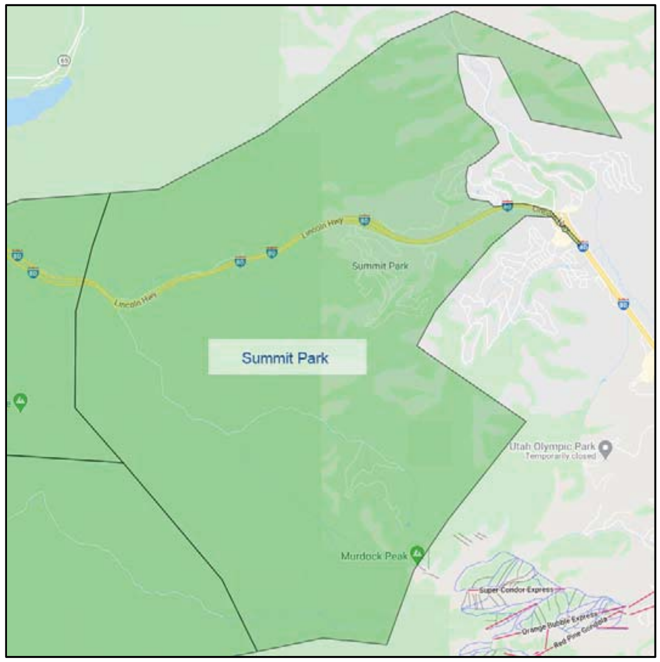

Figure 31. Map of Summit Park Public Safety Power Shutoff Area

Park City. The Park City PSPS focuses on overhead sections of line around Park City. Some underground was included because it could not be isolated. Historic downtown was excluded (and would thus remain energized during a PSPS) because of the prevalence of imperious and irrigated surfaces.

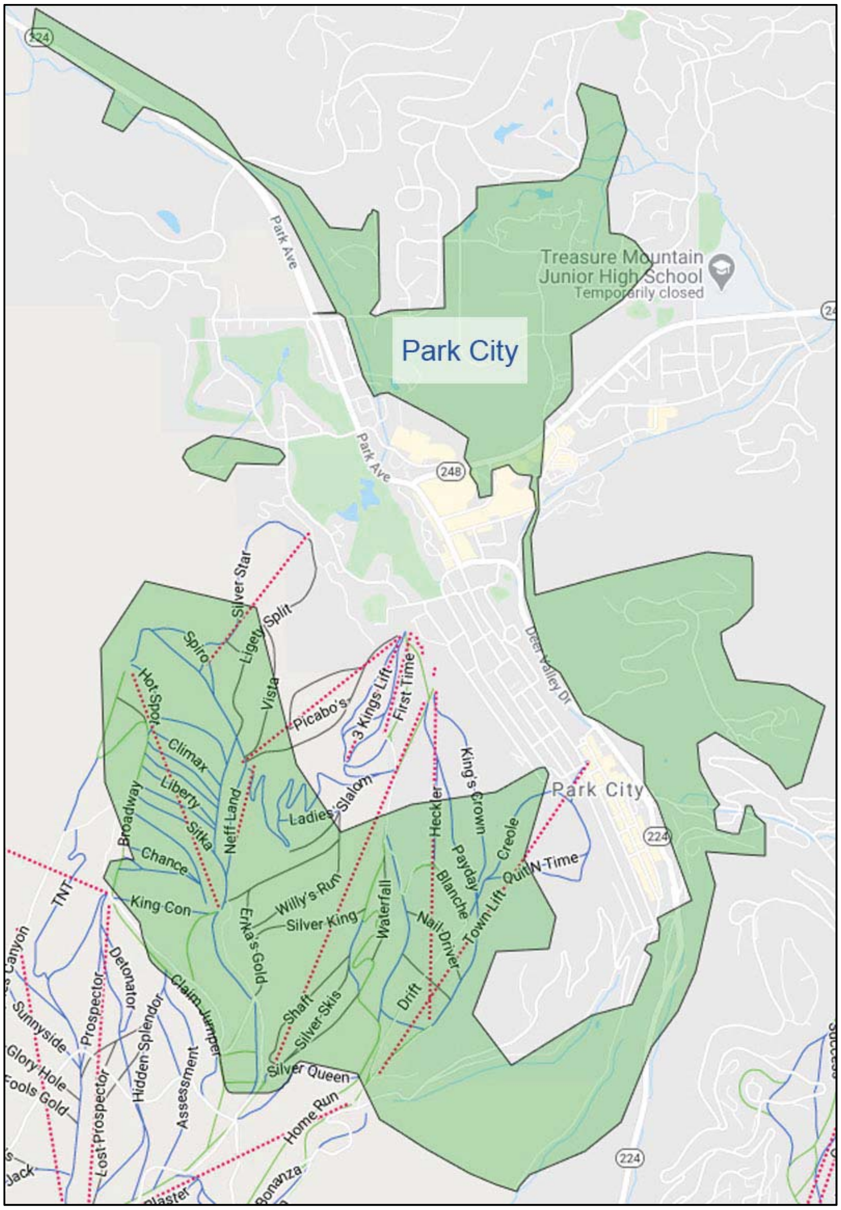

Figure 32. Park City Public Safety Power Shutoff Area

Jordanelle North Shore. The Jordanelle North Shore PSPS includes the entire area north of Jordanelle Reservoir.

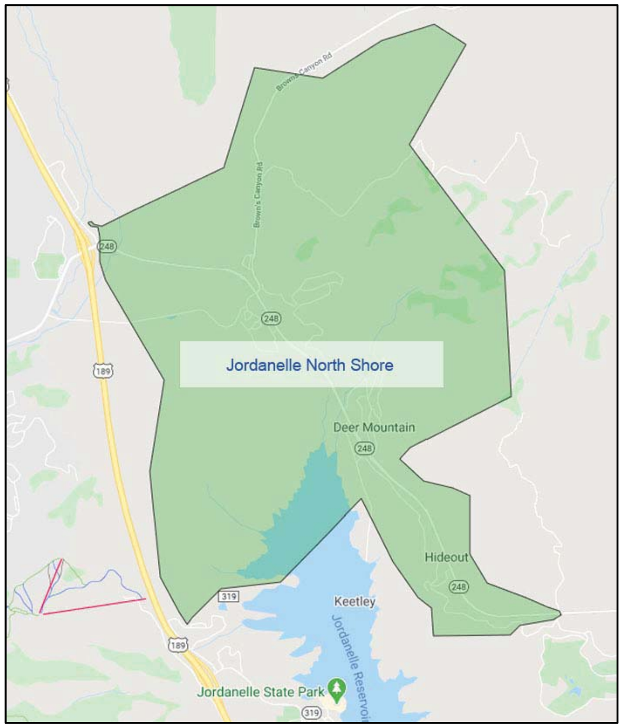

Figure 33. Map of Jordanelle North Shore Public Safety Power Shutoff Area

Wasatch Mountain State Park. The Wasatch Mountain State Park PSPS is the distribution line serving the campground in the Wasatch Mountain State Park and the properties on Snake Creek Road.

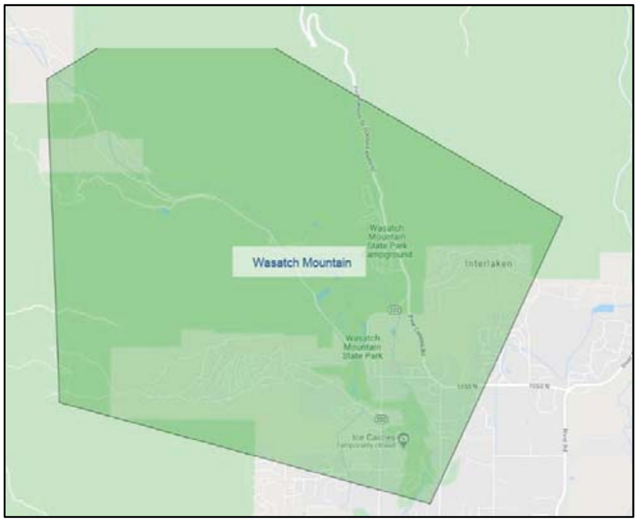

Figure 34. Map of Wasatch Mountain Public Safety Power Shutoff Area

Wallsburg / Sundance. The Wallsburg / Sundance PSPS includes Sundance and the properties east of Provo Canyon up South Fork Road served from the Wallsburg substation.

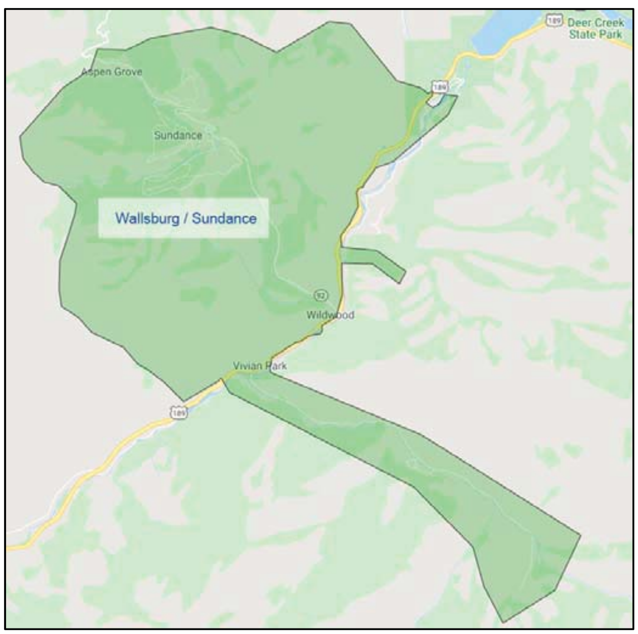

Figure 35. Map of Wallsburg / Sundance Public Safety Power Shutoff Area

Cedar City. The Cedar City PSPS is focused on overhead lines serving subdivisions southwest and southeast of historic Cedar City that are part of the wildland-urban interface.

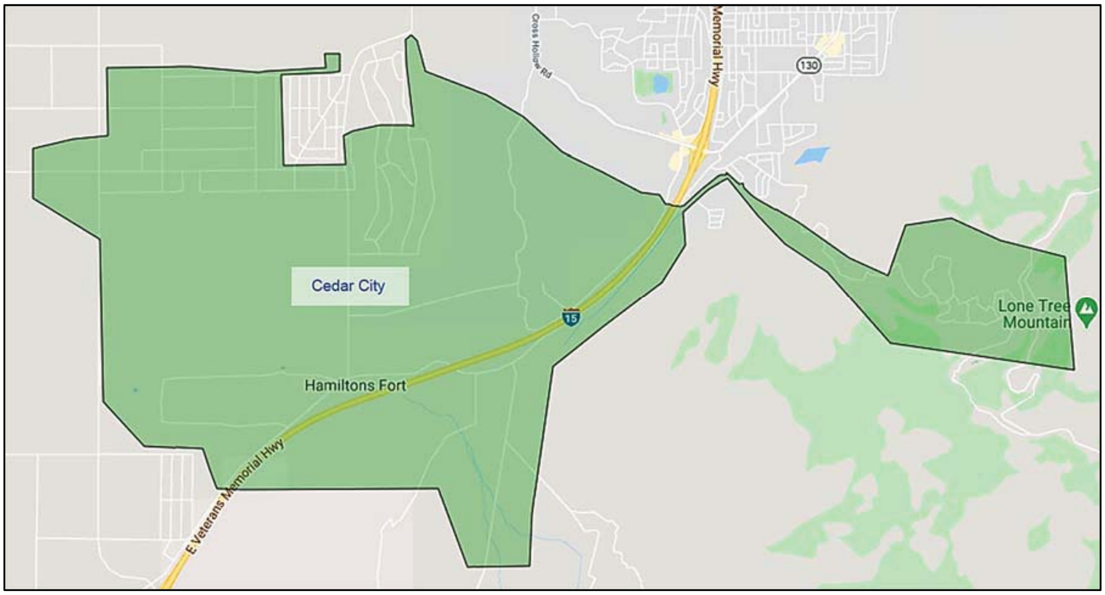

Figure 36. Map of Cedar City Public Safety Power Shutoff Area

10.4. Implementation Protocols

As discussed in the situation awareness section, Rocky Mountain Power engaged a meteorological consultant to perform weather monitoring and forecast services, focusing on the PSPS areas. Every day during fire season, the weather consultant provides a forecast report on each of the PSPS areas. Such forecasts may prompt a notification to customers in a PSPS area of a potential PSPS event. Because weather forecasts are, by nature, inherently speculative, it must be stressed that such notifications only alert customers of the potential of a PSPS event. In 2019, Rocky Mountain Power employed a set of objective criteria to determine whether a notification was warranted. In 2020, the company engaged experts in the Department of Atmospheric Sciences at the University of Utah to assist in refining the metrics that would indicate that a notification is warranted. Rocky Mountain Powers expects that this will be a somewhat iterative process, as the company seeks to find a balance between adequately warning the public of a potential PSPS event versus raising a false alarm too frequently.

After the first notification is delivered, Rocky Mountain Power actively monitors actual weather conditions and endeavors to provide customers with additional notifications. If extreme wildfire conditions are forecast (or measured in actual conditions), Rocky Mountain Power may activate its Emergency Operation Center (EOC), which will closely monitor the electrical network and the weather, in consultation with the expert meteorological consultant. To this end, the EOC may deploy circuit crews in the subject PSPS area, to monitor local environmental and asset conditions on the ground and in real time. The circuit crew lead will have direct communication channels to the EOC. Upon activation of the EOC, the company assembles customer lists in the subject PSPS area and a communication plan for those customers. The EOC is staffed to fill the following primary roles:

Table 14. PSPS Emergency Operations Roles

PSPS Emergency Operations Center Leads				Backup		
All Hazards / PSPS	**LastName**	**FirstName**	**Primary**	**Order**	**LastName**	**FirstName**
All Hazards / PSPS	Mansfield	Curt	Emergency Operations Center Director	2	Ralston	Dana
				3	Bennion	Doug
All Hazards / PSPS	Rich	Bret	Safety Officer	2	Nicholes	Todd
				3	Fewkes	Royce
All Hazards / PSPS	Freestone	Kevin	Operations Section Chief	2	Spencer	Chris
				3	Fryer	Colby
				4	Bodily	Dan
All Hazards / PSPS	Skinner	Wade	Liaison Officer	2	Miyake	Kristyn
				3	Connors-Perez	Teresa
All Hazards / PSPS	Anderton	Steve	Logistics / Resource Section Chief	2	Chapman	Jr.
				3	Stoor	Marv
All Hazards / PSPS	Comeau	Bill	Regional Business Manager Section Chief	2	Morse	Lucky
				3	Area Regional Business Manager	
All Hazards / PSPS	On-Call		Public Information Officer		Eskelsen	Dave
					Erickson	Tiffany
					Hall	Spencer
All Hazards / PSPS	Favero	Kerry	Vegetation Management Section Chief	2	Evans	Dylan
				3	Vanderhoof	Robert
All Hazards / PSPS	Liguouri	Sherry	Environmental Section Chief	2	Norton	Aaron
				3	Edmisten	Scott
All Hazards / PSPS	Earl	Sheri	Emergency Operations Center Support	2	Owen	Jennifer
PSPS	Vickers	Jeff	PSPS Weather Coordinator	2	Johnson	Matt
				3	Attaway	Robin
				4	Wells	Chris
PSPS	Cavazos	Kellan	PSPS Transmission Coordinator	2	Wilson	Nathan
				3	Baye	Dan
				4	Riet	Chris
PSPS	Oakeson	Brian	PSPS Distribution Coordinator	2	Turner	TJ
				3	Squires	Blair
PSPS	Jones	Josh	PSPS Asset Conditions Coordinator	2	Bryson	Chris
				3	Golo	TJ
				4	Moulton	Jon
PSPS	Christofferson	Cindy	PSPS Circuit Crew Coordinator Summit County / Park City	2	Hermreck	Jeff
				3	Lester	Dustin
				4	Martinez	Julene
PSPS	Hermreck	Jeff	PSPS Circuit Crew Coordinator Salt Lake / Wasatch County	2	Lester	Dustin
				3	Martinez	Julene
				4	Rayburn	Ron
PSPS	Lindley	Jeff	PSPS Circuit Crew Coordinator Utah County	2	Staheli	Kevin
				3	Walker	Lance
				4	Ferre	Adam
PSPS	Perschon	Chris	PSPS Circuit Crew Coordinator Iron County / Cedar City	2	Buelte	Rich
				3	Hoggard	Lonnie

Each specific EOC role has a primary person assigned to be responsible for that role, and each primary person has three designated backups.

Based on all of the information available to the EOC, the EOC director may make a decision to implement a PSPS. Consistent with existing regulations and the general mandate to operate the electrical system safely, the EOC has discretion to determine when a PSPS is appropriate or not, at any particular time. In general, barring other unique circumstances, a PSPS would not be implemented unless extreme wildfire conditions have been measured (versus forecast only).

The EOC director will consider all available information, including real-time feedback from other EOC participants and the circuit crew lead in the field, to determine whether PSPS is appropriate. In addition, based on all available information, the EOC director may decide to further refine the PSPS areas described above. As a matter of practical reality, the EOC director cannot know whether a PSPS will prevent a utility-related ignition or not. If a PSPS is not implemented and an ignition occurs, the ignition itself is not proof that a PSPS should have been implemented. Likewise, if a PSPS is implemented, the event itself does not prove that an ignition that would have otherwise occurred was prevented. If the decision to implement a PSPS event is made by the EOC director, the de-energization and restoration is governed by system operating procedures designed for this purpose. Those procedures include a detailed procedure to patrol and visually inspect the entire circuit prior to re-energizing.

10.5. Communication Plan

When there is a potential PSPS event forecast, customers and local government representatives will be provided notice, if feasible. The goal is to begin notifying customers 48 hours in advance of a potential de-energization event. If this is not possible due to rapidly changing weather conditions (or any other emerging circumstances), the notification process will begin as soon as possible. Additional notice will be provided at appropriate times, as conditions are monitored and depending on the circumstances. There is some degree of balancing required. Customers generally want ample advance notice of any actual de-energization. At the same time, recognizing that weather forecasts are inherently speculative, it is possible to overburden customers with notices of “potential” PSPS events that never materialize, especially remembering that Rocky Mountain Power’s fundamental business objective is to keep the grid energized except under the most extreme conditions. Rocky Mountain Power seeks to maintain balance by making information available through multiple outlets.

In sending notices to customers, Rocky Mountain Power seeks to provide customers regular status updates about any PSPS event. In addition to basic information regarding anticipated times of de-energization or re-energization The company will provide information, which may include the following: (a) actions being taken to reduce the need to implement PSPS; (b) updates on actual and forecast weather conditions; (c) criteria being monitored as part of the PSPS evaluation; (d) maps of impacted areas; and (e) restoration information.

Rocky Mountain Power’s communication plan contemplates notices to customers using multiple methods of communication. Direct customer notifications will be a combination of outbound calls, texts and emails. All customers will receive an outbound call at the one-hour mark, the beginning of the event, the beginning of the re-energization, and the cancellation of the event. Other notifications may be made leading up to during an event, at the instruction of the EOC director during the event. The company Rocky Mountain Power may post more frequent updates, leading up and during an event, on its website[14] and through social media. Certain representatives of local government and other community-based organizations are contacted directly by company personnel who are responsible for those relationships.

Additional procedural precautions are taken to make sure that notice of a PSPS is provided to customers with a serious medical condition who depend on electric service for necessary treatment. After an EOC is activated and before a PSPS event, Rocky Mountain Power will attempt, time and circumstances allowing, to make personal contact with vulnerable customers using life support equipment.

10.6. PSPS Mitigation Activities

Rocky Mountain Power is sensitive to the ramifications of a PSPS. Turning off the power is contrary to an electric utility's core mission and culture. And Rocky Mountain Power understands that turning off power can have negative consequences for customers and the public at large. Concerns range from the economic impact that loss of power can mean to business customers, to the inconvenience for residential customers, to the serious implications in loss of power to certain medically vulnerable populations, who might depend on electric power for life-saving equipment. De-energization can also have an impact on public safety. Many irrigation systems depend on electric power. Communications systems can be impacted. Loss of traffic lights can slow down an evacuation. If a loss of power persist, community water and sewer systems are at risk. For all of these reasons, PSPS is the strategy of last resort. In keeping safety as its top priority, however, Rocky Mountain Power may have to implement a PSPS to guard against being a source of ignition. In doing so, the company has also planned certain measures to minimize the impact of such an event.

First, Rocky Mountain Power proactively worked to limit the breadth of a PSPS long before an actual event by be required. As discussed above, the company performed an engineering review to limit, as much as possible, de-energization to those power lines most at risk, being overhead lines in high-risk wildland areas. To facilitate the process, the company has invested in certain protection equipment which allowed the desired isolation of at-risk segments of a circuit.

Second, Rocky Mountain Power included in the PSPS plan measures to notify medically vulnerable populations. Customers who are currently identified as medical baseline for purposes of Electric Service Regulation No. 10 Section 2(c) (Serious Illness) and Section 2(d) (Life Support Equipment) are automatically be treated as vulnerable customers to receive special PSPS notices for medically vulnerable customers. Rocky Mountain Power also provides customers the opportunity to self-identify as a member of a vulnerable population, and the company completed outreach to vulnerable customers through direct mail, town hall-style meetings, social media, and the company's website. In conjunction with this outreach effort,

[14]See https://www.rockymountainpower.net/outages-safety/wildfire-safety/public-safety-power-shutoff.html.

the company engaged with community organizations which serve vulnerable populations to assist in the outreach.

Third, Rocky Mountain Power may deploy mobile generation to help mitigate any impact of a PSPS. Based on local and real-time circumstances, the EOC will decide if deployment is warranted and in what manner deployment would be most effective.

11. Emergency Management and Response

11.1. General Description

Rocky Mountain Power's emergency response to a wildfire is guided by the same principles and procedures that govern Rocky Mountain Power's response to other types of incidents. Whenever electric service is disrupted (or a disruption is threatened), Rocky Mountain Power's emergency response is guided by the National Incident Management System. This basic approach is applicable with respect to any type of wildfire event, ranging from a relatively small wildfire that a local fire suppression agency is able to control, to the larger wildfire events that require a coordinated interagency response. There is, of course, some variation in response driven by the specific characteristics of the event. For example, the governmental emergency responders with whom Rocky Mountain Power will coordinate will be different in a wildfire as compared to other types of events. For small wildfires, Rocky Mountain Power personnel will likely work directly with local firefighters; for larger wildfires, Rocky Mountain Power management will likely coordinate with an incident command center that could involve representatives of both state and federal agencies, likely including the BLM or the National Forest Service. In general, however, Rocky Mountain Power's internal response structure will be organized for a wildfire event in a manner substantially identical to any other incident requiring an emergency response.

The National Incident Management System (NIMS) guides all levels of government, nongovernmental organizations(NGO) and the private sector to work together to prevent, mitigate, respond to and recover from incidents. The NIMS provides shared vocabulary, systems and processes to successfully deliver the capabilities described in the National Preparedness System. In addition, the NIMS defines operational processes, including the Incident Command System (ICS), Executive Policy Group and Emergency Operations Center (EOC) structures that guide how personnel work together during incidents. The NIMS applies to all incidents and is designed to be scalable and, therefore, applicable for incidents that vary widely in terms of hazard, geography, climate and organizational authorities.

Rocky Mountain Power's Emergency Response Plan follows the NIMS and the ICS, and it is the foundation for Rocky Mountain Power's response to all crisis and emergencies. Consequently, Rocky Mountain Power's Emergency Response Plan follows the all-hazards approach, which includes coordinating with other utilities and all levels of government. The plan supports an organized and efficient response to a wide variety of events of differing magnitudes. The all-hazard plan is a management tool providing a scalable response, organizational structure, procedures for information management, operational activities, a smooth transition to restoring normal services and the implementation of post-incident actions. Designed to be interdisciplinary and organizationally flexible, positions are determined by the event and required resources.

Executive Policy Group. The Rocky Mountain Power Executive Policy Group consists of executives and administrators from key internal organizations and is activated based on the severity of the incident and need for strategic support. As part of the structure, the group collects and analyzes information, makes high-level strategic and procedural decisions, assists in the continuation of critical business processes, and helps facilitate cross-platform incident coordination in support of those responsible for managing the incident. Concerns for public safety is a key consideration in determining the need to activate the Executive Policy Group.

Emergency Operations Center (EOC). Bringing representatives from various Rocky Mountain Power organizations together in an EOC optimizes unity of effort and enables staff to share information, provide policy guidance to on-scene personnel, plan for contingencies, deploy resources efficiently, and generally provide any support necessary. The composition of the team may vary depending on the nature and complexity of the incident.

11.2. Emergency Response / Service Restoration

Activation of the response function takes place according to the escalating threat, human impacts or severity of the incident. Incidents that threaten Rocky Mountain Power as a whole (e.g., contagious disease, cyberattacks), or place Rocky Mountain Power's stability at risk, may require high-level management to direct strategic policy, financial decision-making, crisis communications and/or other emergency management functions. During a wildfire event, Rocky Mountain Power will work in coordination with incident command to de-energize lines requested by the incident commander and to remove personnel from restricted access areas. Field personnel's first priority is to provide line work support that may include but is not limited to de-energization of power lines, inspection of assets and restoration activity. Independent fire suppression activity should not interfere with the ability to support the EOC and/or incident command. The operation of the system will be returned to normal as soon as practical, which typically occurs when the incident no longer needs the support and coordination functions provided by the EOC. If assets are damaged by the fire, the return to normal may be delayed until the facilities can be replaced or repaired. If support functions can be managed by individual organizations through normal procedures, operations may return to normal working in coordination with the EOC.

Pre-Incident Preparedness. If an event is anticipated or advanced warning is received (i.e., a winter storm warning), pre-incident activities may be implemented in advance of an actual event. Forecasts of extreme wildfire conditions may warrant pre-incident activities. These activities may include deploying additional response personnel and resources, customer and stakeholder advanced notification, and situational monitoring of wildfire conditions, such as wind speed, temperature, humidity and fuel conditions (all of which might contribute to the ignition and/or spread of a wildland fire).

Response to Incidents. The level of response is dictated by the seriousness of the incident. Incidents may be localized, or they may require support from an EOC. Moderate outage events and localized incidents require localized plan activation. In general, however, localized incidents can be quickly resolved with internal resources. These incidents have little or no impact on the public or normal operations and are managed by supervisors in the impacted district or area.

More complex outage events and potential threats that are beyond the scope of local management often require coordination of a considerable amount of resources, extended involvement and contact with internal business units and external stakeholders, and the potential for the incident to expand rapidly. This type of incident disrupts a significant number of customers, includes extended restoration time, or a perceived threat to service exists beyond the level where normal operating practices and local resources are sufficient to respond, and requires EOC activation. This type of incident might include, for example, a wildland fire, severe weather forecasts or a security threat. Additional personnel from surrounding operations districts may be required to respond.

Mutual Assistance. Electric utilities have the ability to call upon other electric companies for emergency assistance, in the form of personnel, material or equipment, to aid in maintaining or restoring electric service when such service has been disrupted by acts of the elements, sabotage or equipment malfunctions. Rocky Mountain Power is a member of several regional and national mutual assistance agreements with electric service providers. Parties to these agreements can request or provide assistance and resources to other members to support the restoration of electrical service when it cannot be restored in a timely manner by the affected Rocky Mountain Power alone.

11.3. Community Outreach / External Collaboration

Dissemination of timely, accurate, accessible and actionable information to the public is important in all phases of Rocky Mountain Power's incident management. The outage restoration call-back program is an automated system that simultaneously initiates call backs to hundreds or thousands of customers providing updated estimated times for restoration and to verify service has been restored. Communication with customers, key internal and external stakeholders and all levels of management as early as possible is key. The Rocky Mountain Power Joint Information System (JIS) consists of processes and tools to facilitate communication with the public, news organizations, government entities and external stakeholders through social media, website restoration information, press releases and notification protocols while ensuring the messaging is consistent and comprehensive.

Regional Business Managers. Rocky Mountain Power regional business managers maintain Rocky Mountain Power relationships with local government jurisdictions and community organizations. Regional business managers are the primary contact for local leadership and critical customers in their area of responsibility.

District Operations Managers. District operations managers maintain relationships and exchange contact information with local first responders. In the event of a wildland fire, district managers deploy to the jurisdictional agency's Incident Command Post (ICP) to ensure electric safety awareness. The district operations manager acts as the liaison between the ICP and Rocky Mountain Power's Control Center and EOC.

Emergency Managers. Rocky Mountain Power's emergency management group interfaces and maintains relationships with federal and state emergency responders and mutual assistance groups. The emergency manager has contact information for state, county and tribal emergency managers, the state's EOC Emergency Support Functions (ESF) personnel, and the Geographic Area Coordination Centers dispatch centers for fire-related emergency response.

Fire Cause Investigation. Rocky Mountain Power will cooperate with the wildfire incident command to review possible causes, source and origin where Rocky Mountain Power assets were damaged by a fire or when a Rocky Mountain Power asset is potentially involved in the fire origin.

11.4. Training, Exercises and Continuous Improvement

An effective response to any incident is determined by the ability to implement a controlled incident command structure and to assume responsibility for restoration and recovery activities. It is critical that individuals having responsibility for functions within the incident command system are familiar with their responsibilities and have practice performing those responsibilities. Individuals identified with primary or secondary responsibility within the command center structure complete an annual review of the overall disaster response and recovery plan. These individuals are required to contribute to post-crisis and emergency reporting, outlining any issues or concerns regarding their role and responsibilities. The incident command system is activated periodically throughout the year in the normal course of operations. An annual exercise is conducted to ensure that individuals otherwise not involved in incident management on a regular basis are practiced in responding.

Rocky Mountain Power has a goal of continuous incident management improvement. Rocky Mountain Power evaluates exercises and actual response incidents, by identifying issues raised during the exercise or incident and documenting lessons learned and corrective action plans. Multiple methods are used to gather exercise and post-action reviews, including participant and observer evaluation forms, remedial action tracking, and post-exercise or after-action incident reviews. Lessons learned may be implemented for inclusion in Rocky Mountain Power's response and restoration procedures and incorporated in the emergency response document.

12. Performance Metrics and Monitoring

Rocky Mountain Power will regularly evaluate and measure the effectiveness of the wildfire mitigation programs included in this plan. Consistent with UTAH CODE § 54-24-202, the company will file an annual report identifying the actual capital investments and expenses made in the prior calendar year and a forecast of the capital investments and expenses for the present year to implement this plan. In conjunction with preparing this report, Rocky Mountain Power intends to perform an annual assessment the plan. With respect to the wildfire risk mapping and risk assessment activities, Rocky Mountain Power will evaluate currently available data to determine whether the results and conclusions expressed in those sections remain consistent with new information. With respect to the wildfire mitigation activities identified throughout this plan, Rocky Mountain Power will evaluate whether those strategies and programs have been successfully implemented within the planned timeframes. Rocky Mountain Power also expects to learn from the review process and will update or supplement the planned mitigation activities as appropriate. A key metric for evaluating the effectiveness of mitigation strategies, especially as additional years provide additional data, will be the outages during fire season in the FHCA.

The vice president of transmission and distribution operations is the executive sponsor for this wildfire mitigation plan. The following responsible persons have been identified for specific mitigation programs.

Table 15. Rocky Mountain Power Wildfire Mitigation Plan Roles and Responsibilities

Plan Element	Responsible Role	Responsibility
Risk Mapping	Director of Asset Management	Annually evaluate new data to determine whether any modification to the risk-based mapping would be warranted.
Risk Assessment	Director of Asset Management	Annually evaluate risks and integrate new data with risk-based decision-making approach.
Inspect/Correct Programs	Director of Asset Management	Execute inspection and correction program consistent with revised inspection frequencies and correction timeframes.
System Operations	VP of System Operations	Implement system operations procedures during wildfire season and conduct annual review of performance.
Field Operations	Wires Director(s)	Implement fire season policies and arrange for the use of equipment contemplated in those policies.
Environmental	Manager of T&D Environmental	Manage Wildlife Protection Plan and evaluate effectiveness of reducing animal contacts.
System Hardening	Director of Asset Management	Administer proposed system hardening programs and evaluate the utility of adding new projects or reprioritizing planned projects.
Vegetation Management	Director of Vegetation Management	Implement annual vegetation inspections, increased minimum clearances, and pole clearing program
Situational Awareness	Director of Asset Management	Manage installation of weather stations and high-definition cameras.
Public Safety Power Shutoff	Director of Asset Management	Responsible for execution of the plan, including identification, reporting and communication

CERTIFICATE OF SERVICE

Docket No. 20-035-28

I hereby certify that on June 1, 2020, a true and correct copy of the foregoing was served by electronic mail to the following:

Utah Office of Consumer Services	
Cheryl Murray	cmurray@utah.gov
Michele Beck	mbeck@utah.gov
Division of Public Utilities	
dpudatarequest@utah.gov	
Assistant Attorney General	
Patricia Schmid	pschmid@agutah.gov
Justin Jetter	jjetter@agutah.gov
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Rocky Mountain Power	
Data Request Response Center	datarequest@pacificorp.com
Jana Saba	jana.saba@pacificorp.com utahdockets@pacificorp.com
Tim Clark	tim.clark@pacificorp.com

Katie Savarin

Katie Savarin
Coordinator, Regulatory Operations

Rocky Mountain Power
Exhibit RMP___(CBM-2R)
Docket No. 20-035-04
Witness: Curtis B. Mansfield

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Curtis B. Mansfield

Data Response OCS 11.1 - AMI In-service Dates

October 2020

OCS 11.1 (a) (c)
AMI-UT Advanced Metering Infrastructure
Actual Plant in Service addtions/balances through 06/30/2020

Part - a

		FERC Plant Account		
WBS Description	Year/Mo	1064000	3033250	Monthly total additions
AMI-UT - IT (Private Generation)	12/2018	1,224,263.25		1,224,263.25
AMI-UT - IT (Private Generation)	01/2019	(1,224,263.25)	1,225,345.24	1,081.99
AMI-UT - IT (Private Generation)	04/2019		244.13	244.13
AMI-UT - IT (Private Generation)	05/2019		61.03	61.03
		-	1,225,650.40	1,225,650.40

Part - c

		FERC Plant Account		
WBS Description	Year/Mo	1064000	3033250	Monthly total additions
AMI - Utah Energy Usage Web (EUW)	05/2020	517,354.61		517,354.61
AMI - Utah Energy Usage Web (EUW)	06/2020	6,474.26		6,474.26
		523,828.87	-	523,828.87

Rocky Mountain Power
Exhibit RMP___(CBM-2R) 2 of 3
Docket No. 20-035-04
Witness: Curtis B. Mansfield

State	Project	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jul - Dec PPIS 2020
Distribution	AMI - Utah Meters 201	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
General Plant	AMI - Utah IT	$ 281,070	$ -	$ -	$ -	$ -	$ 1,633,451	**$ 1,914,521**
Total	**AMI - Utah**	**$ 281,070**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,633,451**	**$ 1,914,521**

State	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	PPIS 2021
Distribution	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,915,000	$ 13,972,000	$ 2,713,000	$ 4,506,000	**$ 24,106,000**
General Plant										$ 22,298,000	$ 286,000	$ 117,000	**$ 22,701,000**
Total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 2,915,000**	**$ 36,270,000**	**$ 2,999,000**	**$ 4,623,000**	**$ 46,807,000**

Rocky Mountain Power
Exhibit RMP___(CBM-2R) 3 of 3
Docket No. 20-035-04
Witness: Curtis B. Mansfield

Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	PPIS 2022	PPIS Overall
$ 3,568,000	$ 2,796,000	$ 3,217,000	$ 3,019,000	$ 1,378,000	$ 1,827,000	$ 1,947,000	$ 1,239,000	$ 2,468,000	$ 1,220,000	$ 1,180,000	$ 479,000	**$ 24,338,000**	**$ 48,444,000**
$ 538,000	$ 312,000	$ 290,000	$ 101,000	$ 100,000	$ 163,000	$ 150,000	$ 1,166,000	$ 83,000	$ 70,000	$ 70,000	$ 48,000	**$ 3,091,000**	**$ 27,706,521**
$ 4,106,000	**$ 3,108,000**	**$ 3,507,000**	**$ 3,120,000**	**$ 1,478,000**	**$ 1,990,000**	**$ 2,097,000**	**$ 2,405,000**	**$ 2,551,000**	**$ 1,290,000**	**$ 1,250,000**	**$ 527,000**	**$ 27,429,000**	**$ 76,150,521**

Rocky Mountain Power
Docket No. 20-035-04
Witness: David G. Webb

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Rebuttal Testimony of David G. Webb

October 2020

Q. Are you the same David G. Webb who previously submitted direct testimony in this proceeding on behalf of PacifiCorp d/b/a Rocky Mountain Power ("PacifiCorp" or the "Company")?

A. Yes.

I. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony discusses the changes to net power costs in this case to align with the adjustments included by other Company witnesses and responds to various issues and adjustments raised in the direct testimony of the Division of Public Utilities ("DPU") witnesses Mr. Robert A. Davis and Mr. Gary L. Smith, the Office of Consumer Services ("OCS") witness Mr. Philip Hayet, and the Utah Association of Energy Users ("UAE") witness Mr. Kevin C. Higgins relating to net power costs ("NPC").

Q. Please summarize your rebuttal testimony.

A. I discuss the Company's response to the various proposals that affect the NPC in this general rate case ("GRC"). I specifically address the following points:

- NPC changes to align with rebuttal adjustments for wind project updates;
- OCS' proposed adjustment to remove market depth constraints;
- OCS' concern about the Day-Ahead/Real-Time adjustment;
- Parties concerns about including production tax credits ("PTCs") in the Energy Balancing Account ("EBA");
- Impacts to the EBA from the Subscriber Solar II proposal; and,
- DPU's concern about the EBA base revenue update proposal.

II. NPC ALIGNMENT WITH WIND PROJECT IN-SERVICE DATES

Q. Please explain the changes reflected in your revised NPC request.

A. The Company made one change to NPC to reflect the updated timing of the in-service dates of the Pryor Mountain and TB Flats II wind projects as discussed by Company witnesses Mr. Robert Van Engelenhoven and Mr. Timothy J. Hemstreet.

The results of the Company's revised NPC study to align with the wind project changes are provided in Exhibit RMP__(DGW-1R). This NPC revision excludes any of the standard price and contract updates associated with a typical full NPC update. The only revision made was to adjust the Pryor Mountain and TB Flats II wind project in-service dates as model inputs.

Q. How has your NPC recommendation changed from the initial filing?

A. On a total-Company basis, NPC increased by $9.2 million, from $1.421 billion to $1.431 billion. On a Utah-allocated basis, NPC increased from $619.2 million to $622.6 million, a $3.4 million increase from the initial filing but still a reduction of $5.4 million from base NPC of $628.0 million in the last general rate case Docket No. 13-035-184 ("2014 GRC").

Q. Why did the Company forego a full NPC update in its rebuttal filing?

A. The Settlement Stipulation in the 2014 GRC specified that all updates to NPC in future Utah GRCs would be filed at least six weeks prior to the intervenor direct testimony due date.[1] As such, the Company is not updating its NPC at this time.

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[1] *In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations*, Docket No. 13-035-184, Settlement Stipulation at ¶41 p. 12 (June 25, 2014).

III. REBUTTAL TESTIMONY

Modeled Market Depth Constraints

Q. Please summarize OCS' position on the modeled market depth constraints.

A. OCS recommends the Company be required to remove market depth constraints from the High Load Hours ("HLH") in the GRID model. This adjustment reduces NPC by $26.5 million on a total-Company basis or approximately $11.5 million on a Utah-allocated basis.

Q. How does the Company respond to OCS' recommendation?

A. Removing the existing market depth constraint limits—or caps—on market sales will distort the model results in unrealistic ways. As the market caps are derived from actual transactions, they best reflect the actual conditions under which the Company will be hedging and balancing. In actual operations, the Company faces limited counterparty activity and market liquidity at several locations in both the Light Load Hours ("LLH") and the HLH. Those factors are both real and limiting, and they continue to have an effect on optimization efforts and actual NPC. If the caps on market sales are removed, as OCS proposes, none of these current real-world market-limiting characteristics would be represented in the GRID model, which would make the model less accurate.

Q. What market capacity methodology was used in the Company's GRID study in this proceeding?

A. The market capacity in the Company's GRID study reflects a four-year average of historical short term firm transactions, by market, month, and hour class (HLH and LLH). However, no market capacity limits are applied to the Mid-Columbia or the Palo Verde markets because they are the most liquid market points to which the Company has access.

Q. Mr. Hayet argues in favor of removing HLH market caps in GRID because the Public Service Commission of Utah ("Commission") justified its initial 2005 approval of market caps to limit off-peak or LLH sales from coal plants. Has the Commission reviewed market caps at any other point?

A. Yes. While the subject of market caps was initially reviewed before the Commission in the avoided cost docket referenced by Mr. Hayet,[2] the updated methodology, and the basis for adopting it, was originally presented in the direct testimony of Mr. Gregory N. Duvall in the Company's 2010 general rate case,[3] and was also discussed in the direct testimony of Mr. Duvall in the Company's 2014 GRC.[4] The Commission approved market caps in both dockets.

Q. Have the circumstances necessitating market caps in GRID changed dramatically since the Company's 2014 GRC?

A. No. In fact, actual operations provide evidence that the current market caps are sound modeling.

Q. Can you provide an example of some operational data that indicates that the market caps are needed?

A. Figure 1 below compares actual wholesale sales over the period from 2015 through 2019 to the sales forecasted by GRID in the last two GRC proceedings. The approach

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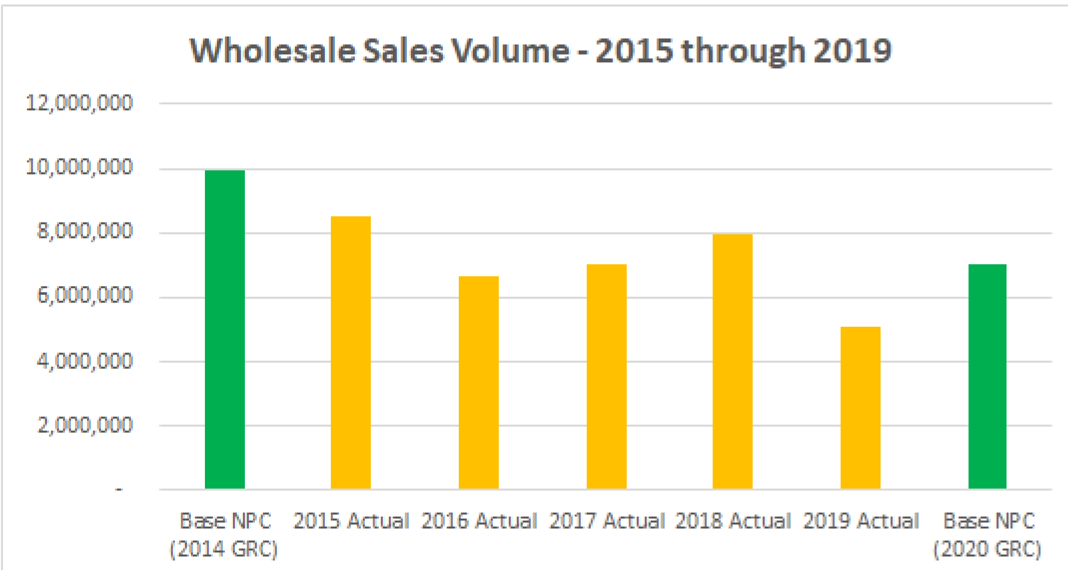
[2] Direct Testimony of Philip Hayet at line 140.

[3] *In the Matter of: the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations*, Docket No. 10-035-124, Direct Testimony of Gregory N. Duvall, lines 209-263 (Jan. 24, 2011).

[4] *In the Matter of: the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations*, Docket No. 13-035-184, Direct Testimony of Gregory N. Duvall, lines 359-419 (Jan. 3, 2014).

to modeling market caps is identical between the two rate case studies. An examination of the figure will illustrate that GRID tends to estimate the Company's ability to sell power into the market with reasonable accuracy—if anything GRID forecasts slightly higher. Without the market caps in place, the model output would be less reflective of actual constraints, which would make the net power cost forecast less accurate as a result.

Figure 1



Q. Mr. Hayet suggests that the removal of HLH market capacity limits represents a reasonable modeling change.[5] Do you agree?

A. No. Mr. Hayet has presented no evidence indicating that the removal of the HLH market capacity limit results in the GRID model producing a more accurate net power cost forecast. In contrast, the history of forecasted sales versus actual sales makes it clear that GRID already projects sales volumes within a reasonable range of actual results. Therefore, I urge the commission to reject the proposed change to market cap

[5] Direct Testimony of Philip Hayet at line 163.

modeling.

Day-Ahead/Real-Time Adjustment

Q. OCS has raised concerns that the Company's "system balancing transaction adjustments" are "complex" and "over-reaching."[6] How do you respond?

A. What OCS refers to as "system balancing transaction adjustments" is in fact the Day-Ahead/Real-Time ("DA/RT") adjustment. The Company incurs system balancing costs that are not reflected in the Company's forward price curve or modeled in GRID. To address this deficiency, the Company uses the DA/RT adjustment to more accurately model system balancing transaction prices and volumes. The Company has been using this adjustment in Oregon, Wyoming, Washington, and California to increase the accuracy of its power cost forecasts.

Q. Please describe how system balancing transactions are included in GRID.

A. System balancing transactions are required to balance the hourly load and resources in the GRID model for the GRC test period. The GRID model calculates the least-cost solution to balance the Company's load and resources each hour. The model makes purchases in the wholesale market (labeled as "system balancing purchases" in the NPC report) in the hours for which the Company does not have enough owned or contracted resources to meet its load. The model also makes wholesale market sales (labeled as "system balancing sales" in the NPC report) when it has excess resources for a given hour.

Q. Please describe the price component of the DA/RT adjustment.

A. To better reflect the market prices available to the Company when it transacts in the

[6] Direct Testimony of Philip Hayet at line 189.

real-time market, PacifiCorp includes in GRID separate prices for forecasted system balancing sales and purchases. These prices account for the historical price differences between the Company's purchases and sales compared to the monthly average market prices.

Q. Why is the DA/RT adjustment needed to differentiate the market prices for purchases and sales?

A. In prior NPC forecasts, before including a DA/RT adjustment, the GRID model only used an hourly price curve developed from monthly HLH and LLH forward market prices. Hourly prices were simply the product of applying a scalar, or shape, to the monthly average prices. These scalars were identical within a given month for each weekday of that month. In addition, the prices were input into the model and did not change regardless of the volume of the system balancing transactions or other system conditions in the model. In reality, however, prices vary within each month and the Company has historically bought more during higher-than-average price periods and sold more during lower-than-average price periods. While there are exceptions to this rule, the average cost of the Company's daily and hourly short-term firm purchases tends to be higher than the average actual monthly market price, while the average revenues from its daily and hourly short-term firm sales tends to be lower than the average actual monthly market price.

Q. Please describe the volume component of the DA/RT adjustment.

A. The Company reflects additional volumes to account for the use of monthly, daily, and hourly products. In actual operations, the Company continually balances its market position—first with monthly products, then with daily products, and finally with hourly products. The products used to balance the Company's forward position in the wholesale market are available in flat 25 megawatt ("MW") blocks. The Company's load and resource balance, however, varies continuously each hour in quantities that may vary widely from a flat 25 MW block. Thus, in real world operations, the Company must continuously purchase or sell additional volumes to keep the system in balance.

In contrast, GRID has perfect foresight and can model wholesale market transactions at whatever volume is necessary to balance the system. Because of GRID's perfect foresight, it can balance the system with far fewer transactions. The DA/RT adjustment adds additional volumes to NPC to more accurately model the transactions necessary to balance the Company's system.

Q. Can you explain why both a Market Cap adjustment and the DA/RT are necessary even when base NPC is trued-up to actual NPC every year in the EBA?

A. These two adjustments serve different purposes and impact the NPC forecast in different ways. The market cap adjustment exists to account for real operational constraints that limit the amount of sales activity the Company can engage in over time. As noted above, a comparison of forecasted and actual sales indicates that the inclusion of this constraint has made the model more accurate. The DA/RT adjustment applies to both purchases and sales and is in place to reflect a different operational reality faced by the company; specifically, it addresses the fact that the Company cannot balance the system with perfect foresight in a single transaction, at precisely the market average price. The DA/RT adjustment also makes the NPC forecast more accurate when compared to actual operationsand both adjustments serve to mitigate changes in the EBA.

Q. Can you explain why it would be inappropriate to include a line item adjustment based on historical data instead of using the DA/RT?

A. A line item adjustment would make this adjustment less accurate. Historical volumes and prices make up the inputs to the DA/RT calculation, but they need to be applied on an average basis to the forecasted purchase and sale volumes in order to match the Company's expectations regarding the expected system balancing costs over time. In addition, the line item approach misses the opportunity to have GRID optimize using a set of expected prices that more closely match the reality that the Company expects to face when executing balancing transactions. As a result of both of those factors, a line item adjustment would reduce forecast accuracy.

Production Tax Credits

Q. Please explain the Company's proposal to include PTCs in the EBA.

A. PTCs are currently included as a fixed revenue credit in base rates, but since actual PTC recovery is tied to actual generation that is captured in NPC, it is logical to treat PTCs similarly for ratemaking purposes. The PTCs associated with the Energy Vision 2020 projects represent a significant source of additional value for customers. PacifiCorp's proposal to track and true-up PTCs through the EBA is designed to pass back to customers the full and actual value of PTCs.

Q. Please summarize the arguments of the parties against a PTC true-up in the EBA.

A. The DPU recommends that PTCs continue to be included in base rates and excluded from the EBA, claiming that including PTCs in the EBA is not expressly considered by Utah law.[7] DPU further contends that including the PTCs in the EBA

[7] Direct Testimony of Gary L. Smith at lines 185-199.

inappropriately transfers risk from the Company to customers.[8] OCS argues that including PTCs in the EBA insulates the Company from regulatory lag and the risks of construction delays and incentivizes the Company to defer maintenance.[9] UAE recommends the PTCs remain in base rates stating PTC values do not change from year to year in an unpredictable manner and would make the potential benefits to customers from the new large wind investments even more variable than they already are.[10]

Q. Please explain how PTCs are calculated for inclusion in the rate case and why it makes sense to include PTCs in the EBA.

A. The PTCs in this case are derived from the annual wind generation forecast as part of the base NPC. In other words, the annual wind generation forecast in the base NPC is then multiplied by the PTC rate and grossed up for taxes to arrive at the total-Company PTC amount that is then allocated to Utah. All other components of base NPC are trued-up in the EBA, and therefore it makes sense that PTCs, which are also derived from the same forecast, should also be included in the EBA.

Q. How do you respond to DPU's statement the PTCs are not expressly included in Utah's Energy Balancing Account statute?

A. It is my understanding that Utah's Energy Balancing Account statute allows for the recovery of incurred actual power costs.[11] Not all components currently included in the EBA mechanism are described in the statute, such as wheeling revenues. My understanding is that the statute language is not necessarily all-inclusive and does not

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[8] Direct Testimony of Gary L. Smith at lines 247-249.
[9] Direct Testimony of Philip Hayet at lines 714-718.
[10] Direct Testimony of Kevin C. Higgins at lines 1185-1187.
[11] Utah Code § 54-7-13.5.

limit other expenses from being included. PTCs vary based on the amount of generation produced by the Company's wind facilities, and so they are intrinsically tied to power costs. Furthermore, they are included in many of the NPC mechanisms that PacifiCorp has in other states including Oregon, California and Idaho.[12] In fact, the Commission has previously contemplated in past orders that it was appropriate to consider the treatment of PTCs in a general rate case.[13]

Q. Do you agree with DPU's characterization that the inclusion of PTCs in the EBA would transfer risk to customers?

A. No. The inclusion of PTCs is not about transferring risk to customers, but rather about ensuring that customers' rates reflect the full costs and benefits of these wind resources. As I discussed above, PTCs are intrinsically tied to the generation output of wind facilities. In fact, all other variable benefits and costs that are tied to the actual generation of the Company's wind facilities are included in NPC. Including PTCs is not shifting risk or harming customers; rather, it ensures that the Company's actual operations are aligned with customer rates.

Q. How do you respond to UAE's assertion that including PTCs in the EBA adds to customer's risk exposure?[14]

A. As I stated above, the inclusion of PTCs is not about increasing variability for customers but about ensuring that customers' rates reflect the full costs and benefits of these wind resources

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[12] PacifiCorp has proposed this treatment in Washington and Wyoming in currently ongoing general rate proceedings.

[13] In 2017, the Commission declined to include PTCs in the EBA but determined they "remain open to reconsider the issue either at the conclusion of the EBA pilot period or during the next GRC." *In the Matter of: the Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism*, Docket No. 09-035-15, Order at 9 (Feb. 16, 2017).

[14] Direct Testimony of Kevin C. Higgins at lines 1176-1177.

Q. Do you agree with UAE that PTC values are not variable enough to justify inclusion in the EBA?[15]

A. No. While the value per kilowatt-hour ("kWh") produced is set in the Internal Revenue Code, the amount of the kWh produced by the PacifiCorp's wind facilities is variable, and it is exactly this type of generation variability that net power cost mechanisms are intended to track. Additionally, inclusion of PTCs in the EBA will allow for a timely update of the PTC rate in the event it is updated for inflation. UAE also ignores similar items like renewable energy credits that have a generation-based benefit.

Q. How do you respond to OCS's assertion that including PTCs in the EBA would insulate the Company from construction delays and incentivize the deferral of maintenance?[16]

A. The Company's EBA is audited on an annual basis in order to determine the prudence of its actions. That review includes the ability to review the outages and comment upon decisions regarding the execution or deferral of maintenance activities. Any argument that the Company is insulated from construction delays or could defer maintenance is unjustified because parties and the Commission have a full opportunity to review the prudence of any outages that occur in the EBA.

Additionally, there has been no evidence that the structure of the EBA affects the Company's operations. When the DPU evaluated PacifiCorp's wind generation before and after the EBA, it was determined that there was no evidence to conclude

[15] UAE contends that because the value of PTCs are set that "[t]here is no PTC price volatility to justify recovery through an adjustor mechanism." Direct Testimony of Kevin C. Higgins at lines 1173-1174.
[16] Direct Testimony of Philip Hayet at lines 714-718.

that any deterioration in wind reliability was a result of the EBA.[17] Similarly it is inappropriate to conclude that the inclusion of PTCs in the EBA will have an effect on the Company's operations.

Subscriber Solar

Q. Please summarize your rebuttal testimony with regards to the Company's proposed Subscriber Solar program.

A. The Company proposes a redesign of the existing Subscriber Solar program to allow for new subscribers, which was described in detail by Company witness Mr. William Comeau in direct testimony. The DPU, OCS and Utah Clean Energy ("UCE") filed testimony with various recommendations regarding the redesigned program, the majority of which are addressed in the rebuttal testimony of Mr. Kyle T. Moore, who has adopted Mr. Comeau's testimony. My rebuttal testimony addresses the parties' questions regarding the implications of the redesigned program on NPC and the EBA.

Q. What concern did the parties raise with respect to NPC?

A. DPU witness Mr. Robert A. Davis recommends that the Company confirm the impacts the migration might have on the EBA.

Q. How do you respond?

A. Any unrecovered costs or unsubscribed portion of the proposed updated Subscriber Solar Program will impact the EBA and be allocated to all Utah customers.

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[17] *See In the Matter of: the Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism*, Docket No. 09-035-15, DPU Final Evaluation of PacifiCorp's EBA at page 34 (May 20, 2016).

Update to EBA Base Revenues

Q. Why does DPU witness Mr. Smith recommend the Commission not approve the Company's proposal to update the base EBA in each annual EBA filing?

A. Mr. Smith's only rationale for this recommendation is his belief that it is inconsistent with the statute enabling the EBA. He argues that Utah Code § 54-7-13.5(2)(f)(ii) allows the EBA collection to "be incorporated into base rates in an appropriate commission proceeding" and that the only appropriate commission proceeding is a general rate case. He then reasons that the Company's proposed change is inconsistent with the law, because it would change base EBA rates outside of a general rate case.[18]

Q. Do you agree with Mr. Smith's conclusion concerning the Company's proposed change to the EBA?

A. No. Mr. Smith may misunderstand the Company's proposed change. The Company does not propose updating base EBA rates in each annual EBA filing, and the Company agrees that base EBA rates should not be changed outside of a general rate case. The Company's proposal is to use the actual revenue collected from base EBA rates established in a rate case instead of the forecast revenue collection from the test period in the rate case in its annual EBA filings. The Company is not recommending that base EBA rates themselves would change outside of rate cases; therefore, the proposed change is not inconsistent with the law. Company witness Mr. Robert M. Meredith will respond to Mr. Smith's recommendation in more detail in his rebuttal testimony in the cost of service/pricing phase of this docket.

[18] Direct Testimony of Gary L. Smith at lines 173-184.

IV. CONCLUSION

Q. Please summarize your testimony.

A. The Company's NPC as modeled in the test period in this case are reasonable and have been aligned with the changes to the wind projects using the most recent data available. NPC have increased slightly from the initial filing but have decreased by $5.4 million on a Utah-allocated basis, since the 2014 GRC. Additionally, I recommend that the Commission approve and adopt the proposed base NPC for the test period of $1.431 billion on a total-Company basis and $622.6 million on a Utah-allocated basis.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Rocky Mountain Power
Exhibit RMP___(DGW-1R)
Docket No. 20-035-04
Witness: David G. Webb

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of David G. Webb

Pryor Mountain and TB Flats II In-service NPC Revision

October 2020

PacifiCorp

Net Power Cost Analysis

12 months ended December 2021	**01/21-12/21**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Nov-21**	**Dec-21**
						$							
Special Sales For Resale													
Long Term Firm Sales													
Black Hills	7,505,785	737,196	563,577	510,677	345,626	371,342	595,055	746,190	736,430	730,562	717,386	703,085	748,658
BPA Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
East Area Sales (WCA Sale)	-	-	-	-	-	-	-	-	-	-	-	-	-
Hurricane Sale	8,780	732	732	732	732	732	732	732	732	732	732	732	732
LADWP (IPP Layoff)	-	-	-	-	-	-	-	-	-	-	-	-	-
Leaning Juniper Revenue	110,091	6,811	7,295	10,304	5,026	5,690	5,945	16,774	16,065	12,717	8,713	6,709	8,041
SMUD	-	-	-	-	-	-	-	-	-	-	-	-	-
UMPA II s45631	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Long Term Firm Sales	7,624,656	744,739	571,604	521,713	351,384	377,763	601,732	763,696	753,226	744,011	726,831	710,526	757,431
Short Term Firm Sales													
COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Colorado	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	1,127,840	371,000	356,160	400,680	-	-	-	-	-	-	-	-	-
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	-	-	-	-	-	-	-	-	-	-	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	4,870,100	1,646,150	1,524,600	1,699,350	-	-	-	-	-	-	-	-	-
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	-	-	-	-	-	-	-	-	-	-	-	-
West Main	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Swaps Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Trading Margin	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Sales	5,997,940	2,017,150	1,880,760	2,100,030	-	-	-	-	-	-	-	-	-
System Balancing Sales													
COB	31,881,523	3,020,200	2,579,436	2,474,810	1,162,453	1,739,822	1,877,226	2,197,159	2,677,109	2,715,413	3,861,799	3,685,397	3,890,698
Four Corners	48,545,245	6,210,978	3,680,010	2,826,755	2,276,103	1,883,355	3,186,455	4,518,645	4,327,539	4,528,690	4,812,456	4,650,612	5,643,646
Mead	29,361,275	3,592,938	3,678,098	1,720,957	973,216	1,054,497	1,519,723	1,957,983	3,157,818	2,577,326	3,095,418	2,858,626	3,174,673
Mid Columbia	29,813,703	1,884,558	1,099,010	542,032	1,638,076	2,266,821	1,113,520	6,059,592	5,195,629	3,188,940	3,150,704	1,965,722	1,709,098
Mona	21,569,797	2,757,569	1,406,112	422,603	721,905	946,669	1,619,485	1,743,951	1,810,503	4,141,864	2,098,885	1,561,602	2,338,650
NOB	6,524,288	440,983	444,265	438,899	617,873	145,307	312,102	1,103,234	1,118,879	582,109	75,206	411,762	833,670
Palo Verde	41,859,367	1,715,707	574,779	1,367,312	2,427,272	2,713,993	4,520,068	7,031,232	8,045,662	5,096,377	2,708,516	2,593,441	3,065,009
Trapped Energy	631	-	-	-	-	-	-	-	-	-	-	631	-
Total System Balancing Sales	209,555,829	19,622,932	13,461,709	9,793,368	9,816,898	10,750,465	14,148,580	24,611,799	26,333,138	22,830,718	19,802,984	17,727,793	20,655,444
Total Special Sales For Resale	223,178,425	22,384,821	15,914,073	12,415,111	10,168,283	11,128,228	14,750,313	25,375,494	27,086,365	23,574,730	20,529,815	18,438,319	21,412,876

Purchased Power & Net Interchange

Long Term Firm Purchases													
APS Supplemental	-	-	-	-	-	-	-	-	-	-	-	-	-
Avoided Cost Resource	-	-	-	-	-	-	-	-	-	-	-	-	-
Cedar Springs Wind	11,723,273	1,348,849	1,095,201	1,032,244	1,016,035	830,825	743,881	742,782	585,990	827,498	1,090,534	1,068,343	1,341,093
Cedar Springs Wind III	8,908,095	1,025,294	832,067	784,236	772,110	631,271	565,348	564,366	445,200	628,830	828,668	811,823	1,018,881
Combine Hills Wind	5,369,068	372,723	451,621	547,613	547,338	465,612	400,323	451,804	378,748	357,771	372,201	456,360	566,954
Cove Mountain Solar	3,863,906	185,318	194,698	339,380	369,458	425,244	457,335	443,628	419,763	359,961	289,769	208,202	171,150
Cove Mountain Solar II	343,571	28,534	28,675	28,713	28,701	28,534	28,701	28,624	28,624	28,609	28,624	28,609	28,624
Deseret Purchase	32,990,071	2,935,583	2,832,069	2,635,138	2,359,940	2,344,792	2,741,178	2,948,207	2,948,207	2,917,910	2,897,712	2,519,000	2,910,336
Douglas PUD Settlement	-	-	-	-	-	-	-	-	-	-	-	-	-
Eagle Mountain - UAMPS/UMPA	2,615,653	156,892	141,048	125,873	128,817	154,170	284,603	436,745	407,435	241,073	156,349	153,679	228,968
Gemstate	1,717,824	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152
Georgia-Pacific Camas	-	-	-	-	-	-	-	-	-	-	-	-	-
Hermiston Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
Hunter Solar	7,122,324	374,917	425,031	647,514	675,791	770,602	797,429	758,093	712,635	664,479	567,050	402,182	326,602
Hurricane Purchase	160,742	13,395	13,395	13,395	13,395	13,395	13,395	13,395	13,395	13,395	13,395	13,395	13,395
IPP Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp Reserves	5,084,680	421,050	425,060	421,050	421,050	421,050	421,050	409,020	429,070	429,070	429,070	429,070	429,070
Milican Solar	2,646,179	68,661	138,221	204,961	257,983	306,199	333,290	375,334	331,656	266,914	174,771	111,940	76,250
Milford Solar	7,081,219	358,636	412,994	609,192	677,611	796,634	839,927	747,990	720,080	671,702	541,717	394,020	310,716
Nucor	7,129,800	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150
Old Mill Solar	-	-	-	-	-	-	-	-	-	-	-	-	-
Monsanto Reserves	19,999,999	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667
Pavant III Solar	-	-	-	-	-	-	-	-	-	-	-	-	-
PGE Cove	154,785	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899
Prineville Solar	1,795,505	82,013	91,830	136,171	171,397	203,430	221,430	249,362	220,343	177,331	116,113	74,370	51,717
Rock River Wind	3,949,010	647,624	502,957	528,679	435,960	284,843	262,621	181,185	193,222	262,771	490,382	158,766	-
Sigurd Solar	2,905,571	-	-	-	-	-	23,671	660,236	605,234	565,052	458,516	322,228	270,634
Small Purchases east	14,288	1,173	1,213	1,172	1,172	1,233	1,203	1,226	1,202	1,153	1,157	1,209	1,176
Small Purchases west	-	-	-	-	-	-	-	-	-	-	-	-	-
Soda Lake Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Buttes Wind	20,662,796	2,790,663	1,806,921	2,135,557	1,618,738	1,425,615	1,202,984	807,052	950,561	1,186,424	1,734,559	2,352,376	2,651,346
Top of the World Wind	40,686,138	5,436,527	3,612,759	4,244,151	3,270,658	2,907,364	2,399,806	1,720,417	1,872,120	2,296,841	3,513,203	4,491,632	4,920,662
Tri-State Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
West Valley Toll	-	-	-	-	-	-	-	-	-	-	-	-	-
Wolverine Creek Wind	10,259,065	760,539	888,633	1,132,686	1,040,512	787,596	844,716	669,522	637,857	752,718	827,852	962,861	953,573
Long Term Firm Purchases Total	197,183,561	19,425,256	16,311,261	17,984,592	16,223,533	15,215,276	14,999,759	14,625,854	14,318,208	15,066,368	16,948,509	17,376,932	18,688,012
Seasonal Purchased Power													
Constellation 2013-2016	-	-	-	-	-	-	-	-	-	-	-	-	-
Seasonal Purchased Power Total	-	-	-	-	-	-	-	-	-	-	-	-	-

Qualifying Facilities													
QF California	2,459,726	215,701	236,633	267,245	312,697	302,769	244,243	166,228	138,407	130,335	133,735	138,107	173,627
QF Idaho	8,526,070	665,205	622,486	675,919	549,840	791,695	853,072	804,323	706,952	676,893	710,906	692,910	775,869
QF Oregon	50,659,824	2,918,983	3,102,799	4,070,906	5,035,956	5,468,588	5,691,241	5,542,450	5,239,793	4,548,585	3,590,005	2,663,496	2,787,021
QF Utah	11,686,984	799,972	834,747	994,336	1,035,869	1,137,833	1,155,642	1,078,323	1,069,390	1,006,203	958,094	845,641	770,935
QF Washington	208,630	-	-	-	3,598	16,682	34,292	47,832	51,603	41,039	13,584	-	-
QF Wyoming	149,045	14,566	13,067	14,455	11,422	10,419	8,672	12,538	12,397	9,613	12,059	12,545	17,290
Biomass One QF	14,325,868	1,137,736	1,170,257	1,267,946	1,426,566	928,933	496,148	1,441,224	1,430,184	1,394,481	1,437,697	1,443,413	751,283
Boswell Wind I QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Wind II QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Wind III QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Wind IV QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Chevron Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
DCFP QF	119,066	3,390	6,084	5,901	4,769	4,661	7,241	17,585	19,050	24,343	12,375	6,980	6,686
Enterprise Solar I QF	12,563,411	617,060	756,870	980,643	1,117,038	1,257,240	1,382,198	1,554,604	1,501,679	1,181,692	957,986	710,651	545,749
Escalante Solar I QF	11,601,502	565,498	685,084	883,730	1,015,842	1,191,044	1,306,249	1,436,464	1,391,659	1,094,914	874,125	648,324	508,570
Escalante Solar II QF	10,921,713	531,489	645,513	832,362	955,502	1,126,572	1,235,898	1,359,761	1,304,268	1,031,738	818,007	606,453	474,150
Escalante Solar III QF	10,520,640	517,551	627,997	806,129	929,679	1,098,975	1,206,563	1,321,201	1,268,974	1,003,181	750,305	555,442	434,642
Evergreen BioPower QF	-	-	-	-	-	-	-	-	-	-	-	-	-
ExxonMobil QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Five Pine Wind QF	8,399,980	515,184	843,295	749,871	802,885	485,845	529,260	630,392	591,216	751,568	738,975	881,157	880,334
Foote Creek III Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Glen Canyon A Solar QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Glen Canyon B Solar QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Granite Mountain East Solar QF	10,913,761	548,826	618,770	895,198	990,554	1,158,651	1,258,453	1,338,832	1,261,328	978,568	810,799	585,874	467,909
Granite Mountain West Solar QF	7,220,477	363,517	409,549	593,815	657,017	766,608	830,760	887,222	834,460	645,109	536,218	387,167	309,035
Iron Springs Solar QF	11,200,371	634,276	666,108	897,183	1,017,893	1,130,820	1,283,100	1,346,598	1,318,721	1,006,219	817,161	582,281	500,011
Kennecott Refinery QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Kennecott Smelter QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Latigo Wind Park QF	9,674,740	1,007,477	917,570	1,126,955	897,120	856,897	745,979	673,722	567,152	616,686	799,252	709,690	756,240
Monticello Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Mountain Wind 1 QF	8,916,080	1,397,705	1,044,898	869,816	693,034	479,607	498,327	410,860	440,933	454,827	672,574	927,984	1,025,515
Mountain Wind 2 QF	13,895,033	2,038,485	1,566,199	1,352,529	1,078,715	750,861	890,296	761,455	734,168	757,712	1,009,557	1,435,299	1,519,756
North Point Wind QF	18,786,576	1,081,867	1,817,411	1,672,826	1,801,611	1,084,057	1,202,040	1,464,551	1,465,394	1,786,186	1,717,960	1,871,542	1,821,132
Oregon Wind Farm QF	12,468,790	729,863	971,742	1,115,635	1,312,368	1,260,505	1,201,740	1,261,216	1,114,406	919,426	735,727	801,716	1,044,447
Pavant II Solar QF	4,310,019	177,389	225,179	346,901	399,215	454,358	476,933	558,197	543,942	425,101	330,218	205,953	166,635
Pioneer Wind Park I QF	10,668,383	1,307,976	927,722	1,190,414	907,777	706,052	651,560	651,076	681,633	452,761	823,624	1,265,841	1,101,946
Power County North Wind QF	5,460,338	415,705	548,470	525,351	519,896	350,950	344,576	370,353	360,112	380,493	511,430	530,622	602,381
Power County South Wind QF	4,865,045	367,049	482,868	474,030	482,998	302,560	306,289	327,761	335,462	336,896	447,464	479,428	522,241
Roseburg Dillard QF	1,042,678	52,652	45,323	49,453	117,831	106,620	104,258	164,486	131,433	66,116	76,189	75,916	52,402
Sage I Solar QF	2,270,456	80,679	79,891	190,158	206,003	234,995	262,709	337,883	333,611	208,547	155,711	104,870	75,399
Sage II Solar QF	2,272,891	80,764	79,986	190,360	206,223	235,208	263,006	338,244	333,976	208,784	155,870	105,000	75,469
Sage III Solar QF	1,870,483	68,007	66,563	157,054	167,907	192,623	214,874	275,730	272,050	172,117	130,624	88,886	64,050
Spanish Fork Wind 2 QF	2,754,893	217,428	177,317	204,533	160,626	154,092	210,749	289,636	315,766	271,043	242,505	250,579	260,620
Sunnyside QF	30,904,807	2,757,966	2,577,196	2,680,631	1,719,211	2,720,081	2,750,586	2,752,683	2,714,248	2,577,478	2,367,927	2,749,169	2,537,628
Sweetwater Solar QF	7,797,376	259,240	374,746	567,022	689,492	814,366	985,566	1,121,979	1,038,739	815,928	628,052	300,112	202,134
Tesoro QF	299,767	50,859	22,516	27,152	24,386	45,902	8,670	11,194	17,560	15,953	18,144	18,180	39,251
Threemile Canyon Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Peaks Solar QF	8,452,878	411,976	477,957	625,721	834,509	860,254	911,132	1,042,848	998,463	794,907	672,624	450,022	372,466
Utah Pavant Solar QF	5,611,720	208,301	240,534	410,490	470,172	563,656	662,527	772,097	721,480	602,883	450,433	279,646	229,501
Utah Red Hills Solar QF	11,565,119	484,032	621,327	787,698	1,034,405	1,204,547	1,240,486	1,530,453	1,463,983	1,326,491	812,004	594,449	465,244
Qualifying Facilities Total	335,365,139	23,244,375	24,504,675	28,500,365	29,590,624	30,255,524	31,455,334	34,102,001	32,724,591	28,714,814	25,929,922	24,005,344	22,337,570
Mid-Columbia Contracts													
Douglas - Wells	-	-	-	-	-	-	-	-	-	-	-	-	-
Grant Reasonable	(373,959)	(31,163)	(31,163)	(31,163)	(31,163)	(31,163)	(31,163)	(31,163)	(31,163)	(31,163)	(31,163)	(31,163)	(31,163)
Grant Meaningful Priority	-	-	-	-	-	-	-	-	-	-	-	-	-
Grant Surplus	2,136,095	178,008	178,008	178,008	178,008	178,008	178,008	178,008	178,008	178,008	178,008	178,008	178,008
Grant - Priest Rapids	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid-Columbia Contracts Total	1,762,136	146,845	146,845	146,845	146,845	146,845	146,845	146,845	146,845	146,845	146,845	146,845	146,845
Total Long Term Firm Purchases	534,310,836	42,816,475	40,962,780	46,631,801	45,961,002	45,617,645	46,601,937	48,874,701	47,189,644	43,928,027	43,025,276	41,529,121	41,172,427

Storage & Exchange													
APS Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
Black Hills CTs	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC II Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC IV Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA So. Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Cowlitz Swift	-	-	-	-	-	-	-	-	-	-	-	-	-
EWEB FC I	-	-	-	-	-	-	-	-	-	-	-	-	-
PSCo Exchange	5,400,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000
PSCO FC III	-	-	-	-	-	-	-	-	-	-	-	-	-
Redding Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
SCL State Line	-	-	-	-	-	-	-	-	-	-	-	-	-
Tri-State Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Storage & Exchange	5,400,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000
Short Term Firm Purchases													
COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Colorado	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	1,094,400	360,000	345,600	388,800	-	-	-	-	-	-	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	-	-	-	-	-	-	-	-	-	-	-	-	-
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	-	-	-	-	-	-	-	-	-	-	-	-
West Main	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Electric Swaps	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Purchases	1,094,400	360,000	345,600	388,800	-	-	-	-	-	-	-	-	-
System Balancing Purchases													
COB	9,434,282	281,484	816,220	1,244,702	453,644	322,282	1,425,102	1,389,787	1,208,360	673,983	114,725	110,464	1,393,529
Four Corners	16,897,467	1,200,558	2,818,880	3,528,287	1,986,636	851,095	89,282	146,158	493,879	1,320,265	1,155,108	1,369,761	1,937,557
Mead	5,190,983	219,078	466,364	370,617	265,777	323,420	351,704	969,326	264,126	371,135	459,020	678,005	452,410
Mid Columbia	68,268,627	4,139,075	3,242,604	1,369,052	2,313,372	10,893,444	7,183,584	15,906,931	13,285,655	3,013,219	1,280,929	1,707,562	3,933,201
Mona	9,992,776	1,306,811	867,955	178,944	488,856	493,672	27,494	1,078,296	946,763	949,130	1,174,806	1,164,648	1,315,400
NOB	13,024,374	864,832	915,796	660,012	981,779	267,714	474,495	2,228,662	2,487,994	1,142,351	242,011	949,795	1,808,933
Palo Verde	1,150,203	95,850	95,850	95,850	95,850	95,850	95,850	95,850	95,850	95,850	95,850	95,850	95,850
EIM Imports/Exports	(64,594,041)	(3,477,483)	(3,102,409)	(8,578,822)	(8,746,296)	(8,972,657)	(3,177,393)	(6,964,351)	(7,193,600)	(4,914,121)	(2,979,604)	(2,911,632)	(3,575,674)
Emergency Purchases	520,874	424	750	251,658	136,693	45,864	3,987	56,102	481	67	24,137	711	-
Total System Balancing Purchases	59,885,544	4,630,629	6,122,010	(879,700)	(2,023,687)	4,320,685	6,474,106	14,906,762	11,589,507	2,651,880	1,566,982	3,165,164	7,361,207
Total Purchased Power & Net Interc	600,690,780	48,257,104	47,880,391	46,590,902	44,387,315	50,388,330	53,526,043	64,231,462	59,229,151	47,029,906	45,042,258	45,144,285	48,983,634

Wheeling & U. of F. Expense													
Firm Wheeling	144,697,684	11,749,372	11,482,343	11,451,463	10,034,554	9,720,807	16,198,114	11,657,890	11,684,246	12,376,159	12,210,595	12,829,755	13,302,386
C&T EIM Admin fee	2,022,748	153,010	131,133	172,440	211,710	248,077	216,704	172,436	135,045	153,613	170,764	127,508	130,308
ST Firm & Non-Firm	30,393	8,032	2,366	803	-	20	666	5,204	4,982	3,613	1,130	1,818	1,758
Total Wheeling & U. of F. Expense	146,750,824	11,910,414	11,615,842	11,624,706	10,246,264	9,968,904	16,415,485	11,835,530	11,824,272	12,533,385	12,382,488	12,959,081	13,434,452
Coal Fuel Burn Expense													
Carbon	-	-	-	-	-	-	-	-	-	-	-	-	-
Cholla	-	-	-	-	-	-	-	-	-	-	-	-	-
Colstrip	15,189,735	1,782,525	1,424,501	1,318,024	963,508	838,704	1,034,344	1,577,600	1,569,277	1,173,339	513,140	1,482,927	1,511,845
Craig	16,859,969	1,493,436	1,337,931	1,418,923	1,293,890	1,416,942	1,187,805	1,521,572	1,637,126	1,327,347	1,421,111	1,314,012	1,489,873
Dave Johnston	49,911,159	4,724,454	4,360,909	3,625,199	3,047,223	3,300,576	3,667,705	4,771,042	5,227,608	4,469,050	4,449,688	3,796,022	4,471,682
Hayden	14,706,480	1,397,927	1,198,893	995,646	1,014,078	1,014,757	1,326,435	1,321,986	1,225,980	1,329,757	1,212,614	1,322,376	1,346,030
Hunter	93,768,329	11,786,622	9,348,741	6,950,045	3,715,810	4,739,883	5,828,742	8,872,928	8,010,343	6,487,735	5,887,233	10,235,310	11,904,936
Huntington	99,698,837	11,731,837	9,584,631	8,453,741	5,354,501	4,777,665	5,479,369	10,035,555	9,831,446	7,546,122	5,921,391	8,485,425	12,497,154
Jim Bridger	209,704,601	16,250,562	16,830,219	18,961,498	13,739,064	10,461,240	15,356,324	24,350,400	23,879,296	18,714,470	18,002,871	17,337,594	15,821,064
Naughton	77,018,796	7,573,959	6,782,498	6,851,646	4,927,856	4,373,120	5,842,501	6,963,124	7,115,510	7,017,292	6,229,835	6,676,167	6,665,288
Wyodak	25,770,686	2,529,932	2,419,392	1,895,341	1,356,060	2,099,656	1,948,623	2,723,586	2,563,907	2,385,463	2,290,068	2,023,539	1,535,118
Total Coal Fuel Burn Expense	602,628,592	59,271,254	53,287,715	50,470,065	35,411,989	33,022,544	41,671,847	62,137,793	61,060,493	50,450,575	45,927,952	52,673,374	57,242,991
Gas Fuel Burn Expense													
Chehalis	46,626,229	5,218,443	1,829,937	3,244,262	2,356,707	3,551,746	2,883,763	4,658,620	4,756,101	4,557,374	5,319,764	2,897,663	5,351,849
Currant Creek	39,664,652	1,338,872	817,861	1,782,405	2,657,650	2,860,523	4,218,020	4,638,824	4,128,433	4,409,529	4,313,083	4,356,835	4,142,616
Gadsby	3,759,815	-	102,758	204,046	77,285	83,671	255,780	714,416	692,813	398,423	250,763	351,861	627,999
Gadsby CT	1,687,860	9,641	31,960	45,743	15,115	17,708	64,715	350,346	298,062	135,942	124,212	141,289	453,127
Hermiston	22,517,661	2,149,713	1,578,406	1,290,632	1,879,819	935,346	1,168,672	2,046,301	2,241,483	2,186,304	2,385,181	2,522,510	2,133,296
Lake Side 1	55,157,156	3,942,458	3,209,965	3,352,655	4,213,087	4,621,639	4,855,078	5,739,350	5,896,729	5,425,244	4,741,359	4,759,322	4,400,271
Lake Side 2	53,691,415	5,428,615	4,288,358	4,136,432	4,358,945	3,830,085	4,830,794	4,761,506	4,794,580	3,851,109	3,932,704	3,992,455	5,485,831
Little Mountain	-	-	-	-	-	-	-	-	-	-	-	-	-
Naughton - Gas	22,964,296	2,803,912	2,016,812	1,386,254	2,377,787	2,548,484	2,035,304	1,679,789	1,489,963	1,015,569	1,838,916	1,394,864	2,376,641
Not Used	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Gas Fuel Burn	246,069,085	20,891,654	13,876,058	15,442,428	17,936,396	18,449,203	20,312,124	24,589,151	24,298,163	21,979,494	22,905,984	20,416,800	24,971,629
Gas Physical	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Swaps	16,779,163	107,958	574,350	2,058,478	1,780,200	1,935,640	1,733,700	1,348,578	1,323,855	1,392,075	2,341,585	1,468,350	714,395
Clay Basin Gas Storage	(29,961)	(132,136)	(104,285)	(29,237)	52,242	52,242	52,242	52,242	52,242	52,242	52,242	(25,669)	(104,331)
Pipeline Reservation Fees	36,317,735	3,030,219	2,915,834	3,039,201	2,993,761	3,034,107	3,009,667	3,074,081	3,071,440	3,015,726	3,050,970	3,014,404	3,068,326
Total Gas Fuel Burn Expense	299,136,021	23,897,695	17,261,957	20,510,869	22,762,599	23,471,193	25,107,733	29,064,052	28,745,701	26,439,537	28,350,781	24,873,885	28,650,019

Other Generation													
Blundell	4,497,520	448,014	356,628	418,112	407,272	415,782	384,237	373,294	385,568	401,632	407,038	225,018	274,926
Blundell Bottoming Cycle	-	-	-	-	-	-	-	-	-	-	-	-	-
Cedar Springs Wind II	-												
Dunlap I Wind	-												
Ekola Flats Wind	-												
Foote Creek I Wind	-												
Glenrock Wind	-												
Glenrock III Wind	-												
Goodnoe Wind	-												
High Plains Wind	-												
Leaning Juniper 1	-												
Marengo I Wind	-												
Marengo II Wind	-												
McFadden Ridge Wind	-												
Pryor Mountain Wind	-												
Rolling Hills Wind	-												
Seven Mile Wind	-												
Seven Mile II Wind	-												
Black Cap Solar													
TB Flats Wind													
TB Flats Wind II													
Integration Charge	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Generation	4,497,520	448,014	356,628	418,112	407,272	415,782	384,237	373,294	385,568	401,632	407,038	225,018	274,926
	=============	===========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========
Net Power Cost	1,430,525,312	121,399,660	114,488,460	117,199,543	103,047,156	106,138,525	122,355,032	142,266,638	134,158,821	113,280,306	111,580,702	117,437,322	127,173,146

REDACTED
Rocky Mountain Power
Docket No. 20-035-04
Witness: Steven R. McDougal

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Rebuttal Testimony of Steven R. McDougal

October 2020

Q. Are you the same Steven R. McDougal who submitted direct testimony in this proceeding on behalf of PacifiCorp d/b/a Rocky Mountain Power ("RMP" or the "Company")?

A. Yes.

I. PURPOSE OF TESTIMONY

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony to respond to and rebut certain issues raised by the Division of Public Utilities ("DPU" or the "Division") witnesses Mr. JJ Alder, Mr. Robert A. Davis, Mr. Eric Orton, Mr. Gary L. Smith, Ms. Brenda Salter, and Mr. Robert J. Camfield. I also address and rebut issues raised by the Office of Consumer Services ("OCS") witnesses Mr. Philip Hayet and Ms. Donna Ramas as well as Utah Association of Energy ("UAE") witness Mr. Kevin C. Higgins. Lastly, I support the recommendations provided by DPU witness Dr. William "Artie" Powell.

My testimony explains and supports the Company's revised overall revenue requirement and a revenue increase of $72.0 million requested in this general rate case ("GRC"). This revised revenue requirement is requested to become effective in rates over two phases. The Company proposes he first phase to be effective January 1, 2021 for $49.5 million, followed by a subsequent rate increase of $22.5 million effective July 1, 2021. Additional details on this two phase proposal are outlined later in my testimony. Various adjustments were made to the original filing that address certain corrections identified by the Company and items raised in the direct testimony of intervening parties to arrive at the Company's revised revenue requirement. I also discuss the Company's opposition to certain adjustments proposed by intervening parties, which are not incorporated into the revised revenue requirement presented herein.

II. RATE CHANGE PROPOSAL

Q. Why is the Company now requesting a two-phase rate change, with the first on January 1, 2021, followed by a subsequent rate change on July 1, 2021?

A. As discussed in the rebuttal testimony of Mr. Timothy J. Hemstreet and Mr. Robert Van Engelenhoven, the Company is anticipating in-service delays for portions of the Pryor Mountain and TB Flats wind projects due to the global pandemic and construction constraints which are beyond the Company's control. A major driver for this rate case is the Company's new capital investments being placed into service along with adequately matching the costs and the benefits associated with the major investment in wind resources. To match the full costs of these projects with the benefits customers will receive, the Company is requesting a delayed rate change to take place on July 1, 2021, after the expected in-service date of the last wind turbines.

Q. This is a change from the Company's direct filing. Why is the Company requesting the Public Service Commission of Utah ("Commission") approve the proposed rate treatment?

A. Although this is a departure from the Company's original filing, the fundamental request is consistent. In the original filing, the Company assumed the entire Pryor Mountain and TB Flats wind plants would be placed in-service prior to January 1, 2021. The previous in-service dates resulted in a full calendar year 2021 revenue requirement being included in the original overall requested increase of $95.8 million. The global pandemic caused by the COVID-19 virus has resulted in constraints and delays in the expected in-service dates of the above mentioned wind plants. Due to this, the Company is now requesting the Commission include the first year revenue requirement for the portion of these resources delayed into the test year in customer rates through a second phase rate increase. The customer benefits of these resources, zero-fuel costs and production tax credits ("PTCs"), have been proposed by the Company to be included in the Energy Balancing Account Mechanism ("EBA") filings and returned to customers accordingly. Additional details on this request are included later in my testimony and in the rebuttal testimony of Ms. Joelle R. Steward.

Q. Is the delayed rate change consistent with the December 2021 Test Year that was approved in this docket?

A. The rate change effective January 1, 2020, is still consistent with the Test Year filed and approved in this docket. The first phase is reflective of the Test Year costs associated with providing safe and reliable services to our customers as of January 1, 2021. The second phase is associated with the delayed in-service projects. This second phase implementation is to align the cost of these resources with the benefits that will flow to customers through the EBA. These cost and benefits were included in the original case using a January 1, 2021 rate effective date; however, were delayed due to the COVID-19 global pandemic as previously stated. The Company is now seeking the full first-year revenue requirement on a delayed basis after the wind projects are completed.

Q. How have the changes in wind plant in-service dates been incorporated into the revised revenue requirement?

A. The Company has reflected the impact of the delays for the wind projects in-service dates in its revised revenue requirement by removing the plant-in-service from the January 1, 2021 rate change. This includes the impact to net power costs ("NPC") and PTCs.

III. TWO-PHASE RATE CHANGE

Q. Please describe the Company's proposal to delay a portion of the overall rate change?

A. Due to the COVID-19 related delays to portions of certain wind plants, the Company is requesting a delayed rate change with a $49.5 million increase to be effective on January 1, 2021 and a $22.5 million increase to be effective on July 1, 2021. The second rate change captures the revenue requirement of the delayed Pryor Mountain and TB Flats wind projects. In the Company's original filing, it expected the plants to be placed in-service by December 31, 2020; however, due to unforeseen delays driven by the pandemic, a [redacted] million portion of TB Flats and a [redacted] million portion of Pryor Mountain are now expected to be in-service in June 2021. To ensure proper alignment of the costs and benefits of these projects, the Company requests that the full first-year revenue requirement, calculated using a 13-month average rate base methodology, be included as part of that delayed rate change. Should the Commission reject the multi-phase rate effective proposal, the Company proposes a change to the revised revenue requirement to include the pro-rated portions of the TB Flats and Pryor Mountain projects that were delayed. Including the pro-rated portions would increase the rate change effective January 1, 2021 from $49.5 million to $61.5 million. Additional details on this proposal are also discussed in the rebuttal testimony of Ms. Steward.

IV. REVISED REVENUE REQUIREMENT

Q. Please describe the calculation of the revised overall revenue increase.

A. The Company's revised revenue requirement of $2.1 billion includes a total increase over current rates of $72.0 million, and is calculated using the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol ("2020 Protocol"). As stated in my direct testimony, the starting point of this rate case uses accounting information from the 12-month historical period ended December 31, 2019 ("Base Period"). The historical data is then analyzed and adjusted to reflect known, measurable, anticipated changes, and to include previous Commission-ordered adjustments that reflect the expected operations of the Company for the 12-month forecasted period beginning January 1, 2021, through December 31, 2021 ("Test Year"). Since the Company's direct filing, several changes have modified the requested revenue increase. A summary of the Company's Utah-allocated revised revenue requirement is provided in Exhibit RMP__(SRM-1R). Details of the revenue requirement calculation, including new adjustments to the revenue requirement, are provided in Exhibit RMP__(SRM-2R).[1] The revised revenue requirement demonstrates that under current rates, the Company will earn an overall return on equity ("ROE") of 8.50 percent in Utah, well below the currently authorized and requested ROE of 9.8 percent.

Q. Please describe the organization of Exhibit RMP__(SRM-2R).

A. Exhibit RMP__(SRM-2R) is the Company's revised Utah Results of Operations Report ("Report") and incorporates all adjustments to the revenue requirement identified in

[1] Confidential pages are provided under separate cover and included as Confidential Exhibit RMP__(SRM-3R).

my rebuttal testimony. The Report is organized in a manner similar to Exhibit RMP__(SRM-3), which accompanied my direct testimony:

- Tab 1 (Summary) contains the Utah-allocated results based on the 2020 Protocol.
- Tab 2 (Results of Operations) details the total-Company and Utah-allocated revenue requirement by Federal Energy Regulatory Commission ("FERC") account and 2020 Protocol allocation factors.
- Tabs 3 through 9 are not provided as part of my rebuttal testimony. These have been provided in Exhibit RMP__(SRM-3) and Confidential Exhibit RMP__(SRM-4), which were included as part of my direct testimony.
- Tab 10 is a new section of the Report that identifies all adjustments made by the Company to the original filing in its rebuttal case and provides details and supporting the calculation of the adjustments. All adjustments in Tab 10 are incremental to the revenue requirement submitted in the Company's direct filing. Confidential pages supporting this tab are provided under a separate cover and included as Confidential Exhibit RMP__(SRM-3R).
- Tab 11 contains the calculation of the final rebuttal 2020 Protocol allocation factors. The energy and coincident peak data are the same as provided in the Company's direct filing.

Q. Please summarize the adjustments the Company is incorporating into the revised revenue requirement calculation.

A. As shown in Table 1, the Company is making the following adjustments to the revenue requirement originally proposed in this case related to corrections identified by the Company and issues addressed as a result of the direct testimony by intervening parties:

TABLE 1

Utah General Rate Case Rebuttal Filing		
	Page No.	$ - Millions
RMP As-Filed Rate Increase		$95.8
Capital Cost - Cost of Debt	2.0	(0.7)
Capital Cost - Cost of Equity	2.0	(22.3)
O&M Escalation Removal		(3.6)
Wheeling Revenue Update	10.1	2.3
REC Revenues Update	10.2	[redacted]
NTUA Revenue Correction	10.3	(0.1)
M&S Inventory Sales Revenue Correction	10.4	(2.8)
Schedule 300 Fees	10.5	(0.7)
Reliability Coordinator Fees	10.6	(1.4)
Transmission Power Delivery Uncollectible Expense	10.7	(0.3)
Insurance Premium Update	10.8	1.8
Wildland Fire O&M Update	10.9	1.5
WEBA - Full-Time Equivalent	10.10	(1.4)
WEBA - UMWA Correction	10.11	(0.7)
WEBA - CY 2021 Annualization	10.12	(0.7)
Rebuttal Net Power Cost Alignment	10.13	3.4
Nodal Pricing Model Update	10.14	0.0
Other Decommissioning Cost – Colstrip - Correction	10.15	[redacted]
Electric Plant Acquisition Adjustment	10.16	(2.2)
Property Tax Update	10.17	4.4
Pro-Forma Tax Update	10.18	6.6
Removal of TCJA Deferred Balances - Correction	10.19	0.3
Pro-Forma Plant Data Update	10.20	(28.9)
Repowering Capital Additions	10.21	0.3
January 1, 2021 Price Change		**49.5**
Pryor Mountain and TB Flats - Phase 2	10.22	22.5
July 1, 2021 Cumulative Price Change		**$72.0**

V. REVISED REVENUE REQUIREMENT ADJUSTMENTS

Return on Equity ("ROE") and Capital Structure

Q. Were any changes to the ROE or capital structure included in your revised revenue requirement?

A. Yes. My rebuttal testimony includes the impact of the lowered 9.80 percent ROE as supported in the rebuttal testimony of Ms. Ann E. Bulkley and Mr. Gary W. Hoogeveen. This reduced the Utah-allocated revenue requirement by $22.3 million. The Company has also incorporated an updated capital structure which lowered the cost of debt from 4.81 percent to 4.79 percent as explained in the rebuttal testimony of Ms. Nikki L. Kobliha. This change reduced the Utah-allocated revenue requirement by $0.7 million.

Wheeling Revenue Update

Q. Please describe the change to wheeling revenue the Company is proposing.

A. The Company identified the need to update the forecasted wheeling revenues, most notably due to a recent FERC approval of the Company's transmission formula rate in the federally-approved Open Access Transmission Tariff. This transmission formula rate, which represents the cost of providing firm transmission service, incorporates all transmission system investments including return on rate base, income taxes, expenses, and other adjustments. Most recently, the transmission formula rate was updated to include the return of Excess Deferred Income Taxes ("EDIT") as a result of the Tax Cuts and Jobs Act of 2017 ("TCJA"). This adjustment, reflected on Page 10.1, Wheeling Revenue Update, increased the revenue requirement by approximately $2.3

million.

Renewable Energy Credit ("REC") Revenues

Q. Please describe Page 10.2, REC Revenues Update.

A. This incremental adjustment incorporates and accepts two changes to the total REC revenue amount as proposed by OCS witness Ms. Ramas.[2] Specifically, these updates include an additional $24 thousand in the Test Year to account for the revised Kennecott REC Supply Agreement and the inclusion of [redacted] in the REC revenues from the Pryor Mountain wind projected associated with the Vitesse, LLC REC agreement.

Q. Did Ms. Ramas propose any additional changes for REC revenues?

A. No. However, Ms. Ramas did recommend eliminating the REC Balancing Account ("RBA") beginning with the rate effective date of this case, and instead using deferred accounting between cases.[3] Based on the materiality of the REC revenues, the Company is not opposed to this proposal. Further details on this proposal are provided in the rebuttal testimony of Ms. Steward.

Navajo Tribal Utility Authority ("NTUA") Revenue Correction

Q. Please describe Page 10.3, NTUA Revenue Correction adjustment.

A. As identified and discussed in the testimony of Ms. Ramas,[4] the Company did not properly adjust approximately $78 thousand of Utah situs revenues in the Base Period for collections from NTUA for the Utah Sustainable Transportation and Energy Plan and Utah Home Energy Lifeline Program. This correction has been incorporated and

[2] Direct Testimony of Ms. Donna Ramas at line 160.
[3] *Id.* at lines 269-287.
[4] *Id.* at lines 348-365.

reduces the Utah-allocated revenue requirement by $0.1 million.

Materials and Supplies ("M&S") Inventory Sales Revenues

Q. Please describe the accounting for inventory sold to customers for applicant built lines.

A. When a customer wants to build their own power line, the Company will often sell them inventory to aid in that process. When an applicant-built line is completed, the Company legally owns the line, but at a zero rate base value. Each month, the Company makes an accounting entry to expense the materials sold to the customers (recorded as a negative revenue) to move the sold inventory into M&S inventory cost of goods sold. The Company then records an offsetting M&S inventory sales revenue as a result of this transaction. Together, these transactions net to zero expense and zero rate base.

Q. Did any party propose an adjustment to M&S inventory sales?

A. Yes. OCS witness Ms. Ramas found that the two sides of this transaction were accidentally accounted for on different allocation factors.[5] This caused the impact of both transactions to net on a total-Company basis but not on an allocated basis. Furthermore, due to accounting accruals and timing differences when M&S inventory is sold, balances theoretically net to zero but variances can exist on a monthly basis. These two items were impacting the Utah-allocated revenue requirement. The Company has accepted this adjustment and changed the allocation of these amounts to correct this issue in future filings, which lowers the Utah-allocated revenue requirement by $2.8 million. This adjustment is reflected as Page 10.4, M&S Inventory Sales Revenue Correction.

[5] Direct Testimony of Donna Ramas at lines 370-386.

Schedule 300 Fees

Q. Please describe the adjustment to Schedule 300 fees proposed by OCS witness Ms. Ramas.[6]

A. In the original filing and as sponsored in the direct testimony of Company witness Ms. Melissa S. Nottingham, the Company proposed to update a variety of Schedule 300 fees such as the returned payment charge and pole cut disconnect/reconnect fees.[7] In addition, the Company also proposed to implement a paperless bill credit program. Ms. Ramas has proposed all Schedule 300 fee changes be included in the revised revenue requirement.[8] The Company previously only included the revenue impact associated with the proposed paperless bill credit program. The Company has accepted this adjustment and included the remaining revenue from Schedule 300 fees as Page 10.5, Schedule 300 Fees. This adjustment decreased the Utah-allocated revenue requirement by $0.7 million. If the Schedule 300 fee changes are not approved by the Commission this adjustment should be removed from the revenue requirement.

Reliability Coordinator Fees

Q. Please describe Page 10.6, Reliability Coordinator Fees.

A. This adjustment updates the reliability coordinator fees included in the case to reflect the expected level of expense during the Test Year. As discussed in testimonies of OCS witness Ms. Ramas[9] and UAE witness Mr. Higgins,[10] the Company's costs for reliability coordinator fees decreased in 2020 compared to the Base Period. This

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[6] *Id.* at line 118.

[7] Direct Testimony of Melissa S. Nottingham at line 53.

[8] Direct Testimony of Donna Ramas at lines 129-159.

[9] *Id.* at lines 542-567.

[10] Direct Testimony of Kevin C. Higgins at lines 748-767.

decrease reflects the change from PEAK Reliability to the California Independent System Operator as the reliability coordinator. The Company has accepted and incorporated this adjustment into the revised revenue requirement.

Q. Did the Company reflect any changes in the adjustments to reliability coordinator fees from those proposed by intervenor parties?

A. Yes. As provided in the Company's response to data request UAE 2.44, approximately $321 thousand of the $2.3 million of the reliability coordinator fee expense listed for calendar year 2020 is actually related to expenses for 2019. The intervening parties' adjustments were prepared using the total 2020 expense of $2.3 million; however, the adjustment included by the Company further removes the amount related to 2019. The total reliability coordinator fees proposed for the Test Year is $2.0 million, a $0.3 million reduction from the amount proposed by intervening parties. This adjustment reduced the revenue requirement by $1.4 million on a Utah-allocated basis.

Transmission Power Delivery Uncollectible Expense

Q. Please describe OCS witness Ms. Ramas's adjustment to transmission power delivery ("PD") uncollectible expense?

A. Ms. Ramas uses the three-year historic balances of the transmission PD uncollectible expense account to recommend an adjustment.[11] Based on this relatively small sample size, Ms. Ramas concludes that the 2019 transmission PD uncollectible expense is significantly larger than the expenses incurred in 2017 or 2018. Rather than removing the one single customer uncollectible expense of $922 thousand,[12] which was the main driver of the higher 2019 expense, Ms. Ramas proposed to entirely remove the

[11] Direct Testimony of Donna Ramas at lines 592-610.
[12] *Id.* at line 589.

transmission PD uncollectible expense from this case.[13]

Q. Have similar transmission PD uncollectible expenses occurred in previous years?

A. Ms. Ramas is correct that a larger than normal uncollectible expense was experienced in transmission PD in 2019 than in the two prior years. However, expanding this to a larger sample and including additional years such as 2015 and 2016 illustrates that while 2019 was unique, larger uncollectible expenses are not uncommon. In fact, Table 2 illustrates that in both 2016 and 2019, the Company experienced higher uncollectible expenses than in the previous year.

TABLE 2

Transmission PD Uncollectible Expense	
2015	17,359
2016	664,066
2017	2,791
2018	298
2019	981,923
3-YR Average	328,337

Q. Does the Company agree with Ms. Ramas's proposal to completely remove transmission PD uncollectible expense? Why?

A. The Company does not agree with Mr. Ramas's proposal to completely remove the 2019 transmission PD uncollectible expense for two reasons. First, it is apparent the Company consistently experiences some level of transmission PD uncollectible expense and removing the balance in its entirety would not accurately reflect a level of

[13] *Id.* at lines 611-629.

expense likely to occur in the Test Year. Secondly, while the Company agrees the transmission PD expense experienced in 2019 was larger than normal, it is not entirely uncommon. Averaging or deferring is an appropriate treatment of items that experience large relative variations year to year. Based on historical transmission PD uncollectible expense, the Company proposes an adjustment to replace the 2019 balance with a three-year historic average. The adjustment to the three-average of transmission PD uncollectible expense is reflected on Page 10.7, Transmission Power Delivery Uncollectible Expense, which reduces the Utah-allocated revenue requirement by $0.3 million.

Insurance Expense

Q. Please describe the update to Insurance Expense the Company included in revenue requirement.

A. The Company's initial case included insurance premiums from August 2019; however, the Company has since received updated information for the August 2020 premiums that more accurately reflects the level of insurance premiums that will be in place for the Test Year as the updated premiums are for policies in effect August 2020 through August 2021. Since the actual policy cost is now known and has increased from $13.9 million to $14.4 million, total-Company, this adjustment is included as Page 10.8, Insurance Premium Update, which increases revenue requirement by $1.8 million on a Utah-allocated basis.

Wildland Fire Mitigation Plan

Q. Did the Company update the costs associated with its Wildland Fire Mitigation Plan in this case?

A. Yes. On June 1, 2020, after the Company's initial rate case filing, its Wildland Fire Mitigation Plan ("Plan") was filed with the Commission in accordance with the Wildfire Planning and Cost Recovery Act.[14] The details of the Plan are presented by Company witness Mr. Curtis A. Mansfield. As I anticipated in my direct testimony, the rebuttal revenue requirement has been updated to reflect the final costs included in the Plan. Accordingly, the Company is providing the incremental Operations and Maintenance ("O&M") cost on Page 10.9, Wildland Fire O&M Update which increased the Utah-allocated revenue requirement by $1.5 million. Capital additions were updated as part of Page 10.20, Pro Forma Plant Data Update. A summary of the revised Wildland Fire Mitigation Balancing Account base is provided as Exhibit RMP__(SRM-7R).

Wages and Employee Benefits

Q. Please describe how the Company escalated wages and salaries for the Test Year.

A. To arrive at Test Year level wages and salaries, the Company started with actual data from the Base Period. Union wages were escalated using contracted wage increase percentages per the collective bargaining agreements with the Company's unions. Non-union wages were escalated using actual and anticipated average percent increases.

[14] Utah Code §54-24-101 et. seq.

Q. Is this methodology consistent with how the Test Year was prepared for the Company's other costs and expenses?

A. Yes.

Q. Did intervening parties have concerns with the calculation of wage increases?

A. Yes. UAE witness Mr. Higgins identified a correction for wage increases projected to occur in the Test Year. The Company should have only included the wage increase for the months the increase is expected in the Test Year.[15] The Company agrees with this adjustment and has reflected this correction in Page 10.12, WEBA - CY 2021 Annualization. After including labor capitalization percentages, the WEBA - CY 2021 Annualization reduces the revenue requirement by approximately $0.7 million on a Utah-allocated basis.

Q. Did Mr. Higgins raise any additional concerns with wages and employee benefits?

A. Yes. As noted in Mr. Higgins's testimony, the Company has experienced a lower employee level by 35.2 average full-time equivalent ("FTE") from the Base Period, which he proposes the Company reflect in the case.[16] The Company accepts the proposed adjustment by Mr. Higgins in Page 10.10, WEBA - Full-Time Equivalent, in the revised revenue requirement. After considering labor capitalization percentages, the adjustment reduced the revenue requirement by approximately $1.4 million on a Utah-allocated basis.

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[15] Direct Testimony of Kevin C. Higgins at lines 575-587.
[16] *Id.* at line 668.

Q. What does Mr. Higgins's recommend with respect to the Company's Annual Incentive Program ("AIP")?[17]

A. Mr. Higgins proposes an adjustment to remove a portion of the Company's AIP that he claims is tied to financial performance and therefore benefits shareholders. Company witness Ms. Julie Lewis explains why these recommendations should be rejected in her rebuttal testimony.

Q. Please explain your understanding of the adjustment proposed by intervening parties related to pension expenses.

A. Both OCS witness Ms. Ramas[18] and UAE witness Mr. Higgins[19] make recommendations regarding the pension settlement cost. As part of the forecasted Test Year, the Company estimated a pension settlement cost of approximately $11.9 million for CY 2021. Both parties propose to include the pension settlement cost by using the Company's proposed position from Docket No. 18-035-48, or amortizing this cost over the average remaining life of plan participants. For purposes of the estimated 2021 pension settlement loss, the amortization period would be twenty years.

Q. Has the Company made any adjustments to pension in the revised revenue requirement?

A. No adjustment has been made to reflect any changes to pension expense or the related prepaid pension asset as part of the revised revenue requirement. Additional details on why this cost should be included in the Company's revenue requirement are addressed in the rebuttal testimony of Ms. Kobliha. Additionally, as discussed in the rebuttal

[17] Direct Testimony of Kevin C. Higgins at lines 593-653.
[18] Direct Testimony of Donna Ramas at lines 442-541.
[19] Direct Testimony of Kevin C. Higgins at lines 704-746.

testimony of Ms. Kobliha, the Company offers an alternative pension balancing account discussed in more detail later in my testimony.

Q. Did the Company make additional revisions or corrections to wages and employee benefits in its revised revenue requirement?

A. Yes. The Company mistakenly included in the United Mine Workers of America ("UMWA") transfer of retiree medical benefits obligation on both Page 4.2, Wages and Employee Benefits and on Page 8.14, Deer Creek Mine Adjustment in the original filing. To correct this double count, the Company removed the UMWA transfer previously included in Wages and Employee Benefits in its revised revenue requirement. UAE witness Mr. Higgins noted this correction.[20] After capitalization, this adjustment shown on Page 10.11, the WEBA - UMWA correction reduces the revenue requirement by approximately $0.7 on a Utah-allocated basis.

Rebuttal Net Power Cost

Q. Please describe Page 10.13, Rebuttal Net Power Cost Alignment.

A. This adjustment revises the Company's NPC as discussed by Mr. David G. Webb in his rebuttal testimony. It is important to note that NPC are only being adjusted to capture the revised in-service dates of the wind projects discussed previously in my testimony and in the rebuttal testimonies of Mr. Hemstreet and Mr. Van Engelenhoven. This adjustment is incremental to the NPC of the Company's original filing. Table 3 below summarizes the total NPC for the Test Year in both filings.

[20] Direct Testimony of Mr. Kevin C. Higgins at lines 564-572.

TABLE 3

Net Power Cost		
$ - Millions	**Total Company**	**Utah-allocated**
As-Filed - NPC	$ 1,422.9	$ 620.8
Rebuttal - NPC	$ 1,432.1	$ 624.1
Incremental	$ 9.2	$ 3.4

Exhibit RMP__(SRM-6R) provides a detailed summary of the base NPC calculation and proposed PTCs, which the Company proposes to reflect in the EBA deferrals beginning with the rate effective date of this case.

Nodal Pricing Model

Q. Please describe the change made on Page 10.14, Nodal Pricing Model Update.

A. The Company included an adjustment to add the estimated software expense related rate base and on-going O&M costs for the Nodal Pricing Model as agreed upon in Appendix D of the 2020 Protocol. In responding to UAE Data Request 3.9, the Company determined that the estimated in-service cost of this project increased from $4.0 million to $4.5 million. Since the Company updated the capital projects for added, removed, or delayed projects as detailed on Page 10.20, Pro-Forma Plant Data Update, this incremental adjustment also includes the incremental revenue requirement for the revised Nodal Pricing Model capital addition amount. This adjustment increases the Utah-allocated revenue requirement by approximately $24 thousand.

Other Decommissioning Costs - Colstrip

Q. Please describe the Other Decommissioning Cost adjustment that was included as Page 6.6 in the Company's original filing.

A. The Company filed contractor-assisted engineering studies of decommissioning costs pursuant to the 2020 Protocol. The Other Decommissioning Costs adjustment included the incremental decommissioning costs as from these engineering studies, spread evenly over the remaining life of the last retired unit of the plants. The Company proposed the amount collected would be deferred to a regulatory liability account and reduced for actual decommissioning costs once known.[21]

Q. Did intervening parties propose any adjustments regarding the treatment of decommissioning costs?

A. Yes. DPU witness Ms. Salter,[22] OCS witness Ms. Ramas,[23] and UAE witness Mr. Higgins[24] recommended a correction to the remaining life associated with the Colstrip plant as part of their revenue requirement. When preparing the original filing, the Company had a formula error in the remaining life calculation for the Colstrip plant in which three years was used instead of the appropriate seven years. The Company also acknowledged this correction as part of the response to data request DPU 4.4.

Q. Does the Company agree with any party's proposed adjustment?

A. The Company agrees in concept with both the OCS and UAE recommended adjustments. It should be noted, the amounts provided by both parties are slightly different due to the functions of the Company's Jurisdictional Allocation Model ("JAM"). The JAM calculates and synchronizes certain allocation factors, interest expense, and cash working capital. Due to this, the impact varies slightly between the Company's impact and the impact calculated by other parties.The Utah-allocated

[21] Direct Testimony of Steven R. McDougal at lines 638-661.
[22] Direct Testimony of Brenda Salter at line 70.
[23] Direct Testimony of Donna Ramas at line 942.
[24] Direct Testimony of Kevin C. Higgins at line 770.

impact of the adjustment to the revised revenue requirement is [redacted]. The adjustment is included as Page 10.15, Other Decommissioning Cost - Colstrip - Correction.

Q. Does the Company support the DPU's adjustment as calculated by Ms. Salter?

A. No. As mentioned previously, the incremental decommissioning costs were proposed to be collected from customers and deferred to a regulatory liability. Although Ms. Salter correctly captured the change to the collection of costs, her calculation did not include the appropriate corresponding change to rate base.

Regulatory Asset - Electric Plant Acquisition Adjustment

Q. Please describe the Regulatory Asset Amortization – Electric Plant Acquisition adjustment.

A. As part of the original filing, the Company included an adjustment to walk forward a regulatory asset balance associated with the electric plant acquisition adjustment to properly reflect the balance that would occur in the Test Year. The electric plant acquisition adjustment is largely a result of the Craig and Hayden electric plant acquisitions and represents the difference between the cost to acquire the plant and the net book value. As noted by OCS witness Ms. Ramas, the amortization associated with these two plants will be fully recovered shortly after the end of the Test Year.[25] Accordingly, Ms. Ramas has proposed the Company buy-down the remaining net book balance of this regulatory asset with TCJA dollars.[26] The Company has accepted this adjustment which reduces the Utah-allocated revenue requirement by $2.2 million. This adjustments is reflected on Page 10.16, Electric Plant Acquisition

[25] Direct Testimony of Ms. Donna Ramas at line 1543.
[26] *Id.* at lines 1545.

Adjustment. An offsetting adjustment to the TCJA balance is also reflected and illustrated in Exhibit RMP__(SRM-5R).

Property Tax Expense

Q. Please describe the method used by DPU witness Mr. Alder when calculating the $164.0 million estimated 2021 property tax expense.

A. Mr. Alder's $164.0 million estimate[27] is based on a single assumption, namely, that property tax expense will increase during each future year by the 3.50 percent average increase[28] in property tax charged from 2011 through 2019. The math underlying Mr. Alder's $164.0 million estimate is shown below in table 4:

TABLE 4

Alder's Calculation

Property Tax Charged for 2019	$153,079,003	a
Multiplied by	103.50%	b
Estimated Property Tax for 2020	$158,436,768	c (a x b)
Multiplied by	103.50%	d
Estimated Property Tax for 2021	$163,982,055	e (c x d)
Rounded Estimate for 2021	$163,982,000	f(e Rounded)

Q. Does Mr. Alder's method produce a valid result?

A. No. Property tax expense increases when assessed values increase. Assessed values are commonly determined by state assessment personnel through the use of the cost and income approaches to value. Values produced by the cost approach increase when the Company's net investment in operating property increases. Values produced by the use

[27] Direct Testimony of JJ Alder at line 131.
[28] *Id.* at line 87.

of the income approach increase when cash flows increase or capitalization rates decrease. The method employed by Mr. Alder produces an invalid and understated estimate of 2021 property tax expenses because it fails to consider the key factors that lead to increased assessed values and, therefore, increased property tax expense. Importantly, assessed values for 2021 will not be determined based upon average changes in prior year tax expense.

Q. Did the assessed values increase by 3.50 percent from 2019 to 2020 as Mr. Alder's method inherently assumes?

A. No. The assessed values for the Company's operating property increased from $13.6 billion in 2019 to $15.6 billion in 2020, an increase of approximately 15 percent.

Q. What are some of the factors that led to the substantial increase in 2020 assessed values?

A. Assessed values for 2020 increased for three primary reasons: 1) a $1.4 billion, or 7.0 percent, year over year increase in the Company's net investment in operating property, 2) year over year decreases in the capitalization rates used within the income approach and 3) the expiration of an adjudicated value mechanism in Oregon which served to limit increases in Oregon assessed values from 2015 through 2019. Mr. Alder's proposal did not consider any of these factors.

Q. Do you expect similar factors to impact 2021 assessed values and to lead to changes in assessed values and underlying property tax expenses?

A. Yes.

Q. Do historical increases in property tax and net investment support Mr. Alder's $164.0 million estimate for 2021?

A. No. As illustrated below and in Figure 2 of Mr. Alder's testimony, property tax charged increased by $36.3 million between 2011 and 2019. This increase in tax occurred during a period when the Company's net investment in operating property increased by $3.0 billion. Hence, property tax charged has increased by $0.012 (or 1.2 percent) for each $1.00 increase in the Company's net investment in operating property.

TABLE 5

Property Tax Increase

	2011	2019	Increase	
	(in millions)			
Property Tax Charged	$116.8	$153.1	$36.3	a
Net Investment in Operating Property	$15,551.5	$18,586.4	$3,034.8	b
Increase in Property Tax for Each Dollar Increase in Net Investment			$ 0.012	c (a ÷ b)

Given that the Company's net investment in operating property is expected to increase by at least another $3.0 billion during 2019 and 2020, property tax expense for 2021 can be expected to increase by as much as $36.0 million ($3.0 billion x 1.2 percent = $36.0 million) between 2019 and 2021, which is more than double the $15.2 million increase recommended by Mr. Alder.

Q. Has the Company made any changes to the property tax estimated as part of the revised revenue requirement?

A. Yes. As previously noted, capitalization rates used by state assessment officials within the income approach decreased considerably from 2019 to 2020. As a consequence, the 2019 capitalization rates which were used when producing the $181.3 million estimate of 2021 property tax expense are no longer valid. A revised analysis using the updated lower 2020 capitalization rates now estimate property tax expense for the Test Year of $191.4 million. This has been included as Page 10.17, Property Tax Update, which increased the Utah-allocated revenue requirement by $4.4 million. A new property tax estimation workbook has been provided as Confidential Exhibit RMP__(SRM-4R).

Removal of TCJA Deferred Balances Correction

Q. Please describe Page 7.7 of Confidential Exhibit RMP__(SRM-3), Removal of TCJA – 3 Year Amortization, that was submitted as part of the original filing.

A. This adjustment reflected the removal of the Non-Protected tax deferral balances as a result of the TCJA that was enacted on December 22, 2017. This adjustment also incorporated the appropriate level of protected EDIT amortization using the Reverse South Georgia Method ("RSGM") to amortize the protected property balances.

Q. Are any corrections required to this adjustment?

A. Yes. As part of the Company response to Data Request OCS 10.2, a mathematical error was noted in calculating the balance used to remove the non-protected property EDIT regulatory liability. This correction is reflected on Page 10.19, Removal of TCJA Deferred Balances - Correction, and increases the Utah-allocated revenue requirement by $0.3 million.

Pro-Forma Capital Additions

Q. Please describe the adjustment the Company included in its rebuttal revenue requirement with respect to capital additions.

A. UAE witness Mr. Higgins proposes an adjustment to update the forecasted plant in-service balances for projects that have been delayed or canceled and are now outside of the Test Year of this case.[29] Mr. Higgins acknowledges that certain projects that were previously not included in the Test Year are now forecasted to go in-service by the end of the Test Year.[30] The Company agrees with the adjustment proposed by Mr. Higgins, revised to include the new capital additions expected to be placed in-service within the Test Year, and has included the incremental impact of this change as Page 10.20, Pro-Forma Plant Data Update.

Q. What projects were modified as part of Page 10.20, Pro-Forma Plant Data Update?

A. The Company included all projects that were identified in the response to UAE data request 3.9 and has noted these projects on Page 10.20.3-10.20.8 of Exhibit RMP__(SRM-2R). The Nodal Pricing Model update is reflected in Page 10.14, Nodal Pricing Model Update which was discussed earlier in my testimony.

Q. What additional capital are included as part of this adjustment?

A. The Company analyzed the changes to the capital forecast used when developing its direct case. Most notably, the Company has revised the in-service dates and/or amounts of major wind plants and of the Advanced Metering Infrastructure ("AMI") project. This adjustment includes only the portion of wind plant capital investment that is expected to be placed in service by the end of December 2020. The remaining capital investment is included as a separate adjustment.

Five other projects were updated; three transmission projects included in the revenue requirement in the Company's initial filing have been updated to reflect the

[29] Direct Testimony of Kevin C. Higgins at line 180.
[30] *Id.* at line 216.

most current forecast, and two projects classified as transmission in the Company's initial filing are classified as distribution in rebuttal and allocated directly to Oregon and Utah.

Finally, as discussed previously the Company included updates to the Wildland Fire Mitigation Plan capital to align with the plan submitted by the Company on June 1, 2020. Corresponding updates to O&M are included on Page 10.9, Wildland Fire O&M.

Q. Has any intervening party proposed adjustments to capital projects that were updated in this adjustment?

A. Yes. OCS witness Ms. Ramas proposed to remove the AMI project in its entirety from this case.[31] The Company continues to support the inclusion of this project as addressed by Company witness Mr. Mansfield in his rebuttal testimony.

Q. Are you aware of other projects in 2021 that are not included?

A. Yes. The Company recently experienced significant storm damage on the distribution system in Utah due to hurricane force winds. In addition, there has been significant damage to the Company's transmission system in Oregon and California due to recent wildfires that has required, and will continue to require over the next several months, major capital investments. Although these events are known at the time of this filing, they are not included as part of the revised revenue requirement because the final costs have not yet been determined.

[31] Direct Testimony of Donna Ramas at line 973.

Q. Has the Company reflected the impact of depreciation expense and accumulated depreciation due to the updated capital forecast?

A. Yes. The Company's adjustment includes depreciation expense, accumulated depreciation, and the applicable impact to deferred taxes. In total, this adjustment, Page 10.20 – Pro Forma Plant Data Update, reduces the Utah-allocated revenue requirement by $28.9 million.

Q. Have any other changes been included as part of the revised revenue requirement as it relates to major capital projects for the Test Year?

A. Yes. Several repowered wind facilities went into service during the Base Period. Accordingly, the Company did not include any adjustment in the original filing to reflect additional capital for the repowered wind plants in the Test Year. Since then, the Company has undertaken final capital punch list and cleanup items, which can follow the in-service date of major plants for up to nine months. Since many of the repowering project were placed in-service in 2019, approximately $5.6 million of the $6.0 million total additional capital included has been incurred and placed in-service. The Company has included this final capital spend related to repowered wind plants as part of the revised revenue requirement. This adjustment increased the Utah-allocated revenue requirement by $0.3 million. Additional support for this adjustment is provided as Page 10.21, Repowering Capital Additions.

New Wind Generation Capital Additions

Q. Please further describe the updates to the Pryor Mountain and TB Flats wind projects?

A. As mentioned previously in my testimony, the Company has experienced unforeseen delays to the estimated in-service dates of the Pryor Mountain and TB Flats wind projects. Specifically, the most recent forecast estimates that approximately [redacted] of Pryor Mountain and [redacted] of TB Flats are delayed and will not go into service until the first half of 2021. The Company has reflected these delays and the associated impacts in the following four adjustments that are included in the revised revenue requirement. Page 10.20, Pro-Forma Plant Data Update, is an incremental adjustment that removes the full revenue requirement including rate base, deferred tax, depreciation expense, and O&M expense associated with the portion of the delayed project. Changes to PTCs and NPC are included under Page 10.13, Rebuttal Net Power Cost Alignment and Page 10.18 Pro-Forma Tax Update, respectively. The revenue requirement impact of each of these adjustments have been included in my testimony under the applicable section. Finally, the full first-year revenue requirement of these projects is added back in as a new adjustment, Page 10.22, Pryor Mountain and TB Flats - Phase 2, and included as the delayed rate change, proposed to be effective July 1, 2021. The Utah-allocated revenue requirement impact of this adjustment is $22.5 million.

Q. Please summarize the parties' positions as they relate to the wind projects.

A. OCS witness Mr. Hayet proposed exclusion of Foote Creek and Pryor Mountain.[32] Additionally, DPU witness Dr. Zenger raised issues with the Pryor Mountain project, but did not remove the revenue requirement associated with the project.[33] Lastly, Mr. Higgins reflects a disallowance of the Pryor Mountain wind project by proposing

[32] Direct Testimony of Philip Hayet at lines 82-107.
[33] Direct Testimony of Dr. Joni S. Zenger at lines 367-386.

a levelized Qualified Facility rate of $26 dollars per megawatt hour in lieu of the revenue requirement.[34] As discussed in the rebuttal testimonies of Mr. Rick T. Link, Mr. Hemstreet and Mr. Van Engelenhoven, the Company opposes these parties' proposed adjustments.

Pro-Forma Tax Data

Q. Has the Company reflected any changes to Pro-Forma Tax Data?

A. Yes. PTCs are calculated based on the generation and eligibility of qualifying wind resources. Due to the changes to the in-service dates and forecasted generation for certain wind plants, the Company updated the PTCs to be proportional to the amount of capital included in the Test Year. In addition to the update to PTCs, the Company is filing a Form 3115 with its 2019 federal income tax return for an automatic change in the accounting method for income tax purposes. For certain property placed in-service between September 28, 2017 and December 31, 2018, the Company did not previously take bonus tax depreciation due to ambiguities in the tax law. Subsequent clarification from the Internal Revenue Service made clear the property was eligible for bonus tax depreciation. On a total-Company basis, the additional tax depreciation that will be taken for 2019 as a result of this filing is $12.2 million, or $3.0 million tax effected. The Company has reflected the associated impact of this accounting change in this adjustment as reflected on Page 10.18 – Pro Forma Tax Update. In total, both adjustments increase the Utah-allocation revenue requirement by $6.6 million.

Q. Would you like to further address PTCs?

A. Yes. The Company's filing includes a proposal to true-up PTCs annually in the EBA.

[34] Direct Testimony of Mr. Kevin C. Higgins at lines 780-945.

This true-up captures actual changes in PTCs, including both the price (PTC rate) and volume differences of (PTC eligible wind production) for all wind projects included in Utah, commensurate with the amount of capital in the Test Year. Additional support for including PTCs in the EBA is provided in the rebuttal testimony of Mr. Webb.

Q. Please clarify what you mean by "commensurate with the amount of capital in the Test Year."

A. The Energy Vision 2020 projects and other wind projects included in this case provide customer benefits at a lower cost to customers largely due to the qualification of PTCs. The overall project revenue requirement including the "return of" and "return on" these resources are largely offset by the PTC tax benefits. Due to the COVID-19 global pandemic, the Company is experiencing delays to the in-service dates for two Energy Vision 2020 projects, specifically the TB Flats and Pryor Mountain wind projects. These delays are the reason for the alternative rate recovery proposal by the Company whereby the revenue requirement for these resources is included as a delayed rate change effective July 1, 2021. Upon inclusion of these and any future projects in customer base rates, the Company will include the PTC benefits associated with these resources in the EBA filings. Additional details on these delays are provided in the testimonies of Mr. Hemstreet and Mr. Van Engelenhoven.

Q. Is the impact of this alternative rate recovery proposal that the Company would not pass back 100 percent of the PTC benefits through the EBA?

A. No. The Company will pass back 100 percent of the PTC benefits associated with wind plants whose capital amounts are included in rates. If the Commission decision approves the multi-phase rate change proposed by the Company, then the Company would simply include the PTC benefits of all wind projects that are included in base rates and continue to true-up the amount in base rates to actual PTCs through the EBA, only adjusting the timing to properly align the PTCs with the amount of capital in rates. Under the Company's proposal, PTCs for all wind plants included in this case would similarly be included in the EBA and trued-up each year. If the Commission were to propose an alternative recovery; for example, a revenue requirement inclusive of the 13-month average revenue requirement for the delayed wind projects, the Company instead requests to retain the PTCs only for that portion not included in customer base rates.

Q. How would the Company make this adjustment to ensure proper alignment of the capital costs for wind projects with the PTC tax benefits?

A. To explain this, I will break my answer into two separate examples. The first example applies to any deferral period that corresponds to the Test Year of a given rate case. In this example, the Test Year uses 13-month average rate base through December 31, 2021, which corresponds with the EBA deferral period of 2021. If the Commission were to deny the Company's proposed delayed rate change and elect only to include a portion of the full revenue requirement, then customers would receive 100 percent of the PTCs benefits for only the portion of wind capital costs that are included in base rates. The Company would separately identify all wind projects, or portions of projects, that are not included base rates and make an adjustment to only include the PTC tax benefits associated with wind projects, or portions of projects, whose capital cost are included in base rates. Tracking by project ensures that customers receive the full PTC benefits for all projects that are included in base rates and, therefore, properly aligns the PTC benefits with the in-service date of the wind assets.

In the second example, the EBA deferral periods are after the Test Year of a GRC. In this case, the Company would apply a weighted percentage, by project, to the total PTCs.

VI. ANALYSIS AND RESPONSE TO OTHER ISSUES

Q. Did the parties propose any adjustments to the revenue requirement that the Company does not believe are appropriate in this case?

A. Yes. This section of my testimony addresses some of the proposed adjustments that are not appropriate and have not been incorporated into the Company's rebuttal revenue requirement.

Miscellaneous Revenues and Expenses

Q. Please describe DPU witness Mr. Orton's adjustment to remove lobbying, civic goodwill and incentive expenses from the revenue requirement?[35]

A. Mr. Orton proposes to remove certain expenses related to lobbying, civic goodwill, and incentive and perks on the basis that the Company's costs for these items do not provide a direct, quantifiable benefit to customers and are not necessary in providing safe and reliable electric service to customers.

Q. Do you agree with Mr. Orton's adjustment to remove the expenses associated with lobbying?[36]

A. No. In data request DPU 13.1, the Division requested the invoices associated with the Edison Electric Institute ("EEI") and the National Hydropower Association. Included on the invoice is a specific amount for lobbying activities, which is approximately 13

[35] Direct Testimony of Mr. Eric Orton at line 10.
[36] *Id.* at lines 22-30.

percent of the total invoice. The Company's response to the data request also included details showing that the portion of these transactions that are related to lobbying activities are booked to FERC account 426.4 (below the line) while the remaining portion is booked to FERC account 930.2, which is included in regulated results of operations. Thus, the balance associated with lobbying that Mr. Orton proposes to remove is not included in the Company's revenue requirement, so an adjustment to remove it is not necessary. In addition, it should be noted the membership dues for EEI are billed to PacifiCorp's parent Company, Berkshire Hathaway Energy. Of the $2.2 million total amount billed, only $1.0 million is allocated to the Company. Mr. Orton's adjustment is incorrectly calculated on the total Berkshire Hathaway Energy amount, not the amount allocated to the Company. For these reasons, the Company does not accept Mr. Orton's adjustment.

Q. Do you agree with Mr. Orton's adjustment to remove expenses associated with civic goodwill?[37]

A. No. Contrary to Mr. Orton's arguments to remove these costs from the case, the Company's participation in these organizations does, in fact, provide benefits to customers and is not for the purpose of increasing load or sales. Participation in these organizations provides basic information which aids the Company's development of its load forecasts and planning to meet the utility service needs of the communities we serve. Chamber of commerce meetings are often a source for learning about new load planned in a community or other matters which might impact the Company's infrastructure or service protocols in the community. Participation in these

[37] *Id.* at lines 31-40.

organizations is critical to the Company's efforts to remain informed on these issues and to build and maintain the relationships with community leaders.

Removing these costs from rates would disallow recovery of costs incurred by the Company that result in benefits to our customers. For these reasons, the Company rejects Mr. Orton's proposed adjustment.

Q. Do you agree with Mr. Orton's adjustments to remove expenses associated with 'incentives'?[38]

A. Mr. Orton has identified a variety of expenses related to leadership conferences, employee appreciation events, and business trips which he identifies as being related to "incentives and perks". Leadership conferences, which account for approximately $133 thousand of Mr. Orton's $410 thousand adjustment, provide training, education, and strategic opportunities for the Company's leadership team to improve their leadership skills and build important relationships in order to provide safe and reliable service for our customers. These are not perks or incentives for the Company's employees. Mr. Orton's assertion that employee appreciation expenses do not provide a benefit to customers is unfounded. The Company's employee appreciation efforts aides its ability to attract and retain talented employees. Recognizing dedicated, hard-working employees for their contributions to the workplace is a reasonable expense for which the Company should be allowed to recover in rates.

Mr. Orton's adjustment also removes approximately $51 thousand in business travel expenses, of which approximately $6 thousand were already removed by the Company in its original filing. In response to a Company issued data request to the

[38] *Id.* at lines 41-47.

DPU, RMP 2.1 Mr. Orton further recognized these business trip transactions were assumed to be related to a prior period. Based on the Company's expense policy, employees have a specific time frame in which expense reports can be submitted for reimbursement. This can have the effect of inclusion of certain expenses related to a prior period but the exclusion of certain expenses related to the Base Period. For example, a December 2018 transaction could be included in the Base Period but a similar December 2019 transaction may be excluded from the Base Period. Overall, the Company has deemed the amounts recorded are simply an estimate of amounts expected for the Test Year. Additionally, the DPU response to Company issued data request DPU 2.1 also infers these expenses are incorrectly recorded in FERC account 921, Office Supplies and Expense. The Code of Federal Regulations specifies that meals, traveling, and incidental expenses as being an appropriate expense for FERC account 921.[39] For all these reasons, I do not support Mr. Orton's adjustment to remove these balances.

Operations and Maintenance Escalation

Q. Please explain the adjustment to the escalation of non-labor O&M costs proposed by UAE witness Mr. Higgins and OCS witness Ms. Ramas.

A. Mr. Higgins' proposed adjustment removes the increases to non-labor O&M expense through the application of IHS Markit Inc. ("IHS") escalation factors as projected for the Test Year.[40] Ms. Ramas proposed adjustment accepts the Company's inclusion of O&M escalation on non-labor O&M expense accounts; however, she has proposed that

[39] 18 CFR §101 (FERC 921 Office Supplies and Expense, number 11).
[40] Direct Testimony of Kevin C. Higgins at lines 501-512.

the Company update the IHS to a more recent release, with corrections that are addressed later in my testimony.[41]

Q. Please explain the rationale used by Mr. Higgins to remove the escalation of non-labor O&M costs.

A. Mr. Higgins's proposed adjustment removes the increases to non-labor O&M expense through the application of IHS escalation factors as projected for the Test Year. He cites two primary concerns: (1) including a provision for escalation in rates makes inflation a "self-fulfilling prophecy";[42] and (2) including escalation in the Company's rates builds a "cost cushion" and provides a disincentive for the Company to improve efficiency.[43] His adjustment reduces the Company's Utah-allocated revenue requirement by $3.6 million.

Q. Has the Commission ruled favorably on the use of escalation rates?

A. Yes. In Docket No. 07-035-93 the Commission stated, "In this case, we find use of Global Insight inflation forecasts is appropriate and provide the Company adequate incentive to manage their non-labor O&M costs (other than net power costs)."[44]

Q. Have any parties provided support to justify inflationary pressures?

A. Yes. DPU witness Mr. Camfield also prepared a fairly in-depth analysis of inflation based on yield differences and national surveys.[45] While Mr. Camfield never proposes

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[41] Direct Testimony of Donna Ramas at lines 809-860.
[42] Direct Testimony of Kevin C. Higgins at line 509.
[43] *Id.* at line 514.
[44] *In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations, Consisting of a General Rate Increase of Approximately $161.2 Million Per Year, and for Approval of a New Large Load Surcharge,* Docket No. 07-035-93, Erratum Report and Order on Revenue Requirement at 79 (Aug. 21, 2008).
[45] Direct Testimony of Robert J. Camfield at lines 198-328.

an adjustment to the revenue requirement as a result of this analysis, he does provide support inferring that inflation is real and has been experienced in prior years. Additionally, Page 16 of his testimony states: "I project overall price inflation for the U.S. to likely reside in the range of 1.75 to 2.00 percent over the years 2021 – 2023…"

Q. Why does the Company oppose Mr. Higgins's adjustment?

A. Mr. Higgins's position that including a forecast of inflation in the Company's case becomes a self-fulfilling prophecy is overreaching. The proposed adjustment is based solely on his interpretation of high-level, macro-economic indicators and not empirical evidence of the cost pressures facing the utility industry and the Company. The Company is simply reflecting the cost of goods and services that it projects to experience during the Test Year. If these cost increases are not reflected in the Company's projected revenue requirement, it will impact the Company's ability to recover the costs necessary to serve customers during the rate-effective period.

Q. Does the Company agree that including escalation serves as a "cost cushion" for the Company?

A. No. Planning for the costs the Company will incur in providing service to customers during the Test Year is not a cost cushion, but rather an accepted practice in setting rates that will allow the Company an opportunity to recover its prudently incurred costs as needed to provide safe and reliable electrical service. Mr. Higgins purports that the use of the forecasted test year in this case is reaching "increasingly further into the future" and that "RMP should not be rewarded with a windfall mark-up of its baseline costs…" (Ref Line 533). In fact, the Test Year for the current rate case was specifically selected to align with the rate-effective period. This is the period when the Company is to provide services to customers, and in doing so, this is also the period when the Company will be making the O&M expenditures. It is evident, then, that O&M expenses should rightfully be matched to the real economic dollars of the rates paid by customers. To reject any adjustment to O&M for inflationary pressures would mean that rates will continue to be set based on expenses at 2019 levels, while the Company's actual expenses are incurred at 2021 levels. This will result in chronic under-earning and does not afford the Company a reasonable opportunity to earn its authorized return and counters the objective of ameliorating regulatory lag.

Q. Does the escalation of O&M expense create a disincentive to O&M efficiency efforts?

A. No. In fact, the Company has managed costs and drastically improved O&M efficiencies in spite of the inclusion of an O&M expense escalation adjustment in past cases. This has allowed the Company to stay out of rate cases and minimize customer rate impacts since the 2014 GRC, Docket No. 13-035-184. The Company will continue to manage costs, but inflationary pressures are inevitable and out of the Company's control.

Q. Were there any other concerns raised by parties regarding the O&M escalation adjustment?

A. Yes. Ms. Ramas proposes the Company update the IHS factors used in the original filing with a more recent forecast.[46]

[46] Direct Testimony of Donna Ramas at lines 841-850.

Q. Did the Company provide Ms. Ramas with information necessary to accurately calculate O&M escalation based on the most recent IHS factors?

A. Yes. As part of data request OCS 5.1, the Company provided the most recent IHS report which was dated as Quarter 1, 2020. As part of this data response, the Company noted these factors included a preliminary estimate of the impacts of the global pandemic.

Q. Do you believe the Quarter 1, 2020 IHS factors should be used for purposes of this case?

A. No. During the preparation of this case, the global pandemic was in the inception phase with total impacts largely unknown. Today, although much more is known about the global pandemic, there is still a tremendous amount of uncertainty. For example, the Company is still evaluating and determining the near-term and long-term impact that the pandemic could have on loads and the underlying load based allocation factors. Furthermore, any change in load would have a resulting impact on revenues. Each of these items could dramatically impact the calculation of revenue requirement. To include the impact of the updated escalation forecast without incorporating the impact to all other costs and revenues does not accurately represent the total change of the COVID-19 pandemic.

Q. Has the Company included the additional impacts of the pandemic?

A. No. As mentioned earlier, the long-term impacts of the global pandemic are still being evaluated. Given the uncertainty and difficulty forecasting such an unprecedented event, the Company's best estimate of the cost and revenues expected to occur during the Test Year are those associated with the Company's revised filing.

Q. Has the Company made any adjustment to O&M escalation?

A. Yes. Due to the overall uncertainty of escalation as a result of COVID-19, the Company has removed all non-labor escalation from the revenue requirement. This adjustment reduced the Utah-allocated revenue requirement by $3.6 million.

Q. Does this mean the Company accepts the proposal as set forth by UAE witness Mr. Higgins?

A. No. The Company has only removed the O&M escalation due to the overall uncertainty that exists around escalation related to current conditions associated with the pandemic. To adequately, reliably, and safely provide service to our customers, the Company is constantly spending money on goods and services. These goods and services have experienced inflation in prices which are then realized by the Company. This is the fundamental reason why it is necessary to normalize generation overhaul expenditures in today's dollars, discussed later in my testimony. However, the questions around future price increases on goods and services as a result of COVID-19 are not apparent. Given this uncertainty, the Company has elected to remove all non-labor O&M escalation but reserves the right to argue for inclusion of escalation in future GRC proceedings.

Q. Did intervening parties propose any additional adjustments to non-labor O&M escalation?

A. OCS witness Ms. Ramas noted two corrections that should be included in the Company's revenue requirement: removal of escalation on uncollectible expense and removal of escalation on an employee benefits cost that is accounted for under two different FERC accounts, FERC 929 and FERC 929.[47]

DPU witness Mr. Davis also noted one correction that was also identified in the Company's response to Data Request OCS 12.8 which inadvertently escalated costs associated with the subscriber solar program.[48]

Based on the Company's exclusion of all non-labor O&M escalation in rebuttal, the corrections as proposed by Ms. Ramas and Mr. Davis are no longer required.

Generation Overhaul Expense

Q. Please explain Ms. Ramas's adjustment to Generation Overhaul Expense.[49]

A. Ms. Ramas proposes to reduce revenue requirement on a Utah-allocated basis by $2.4 million. This proposed reduction removes the adjustment applied by the Company to restate the prior year overhaul expense to a December 2019 level before calculating the four-year average level of overhaul costs.

Q. Is the Company's position that generation overhaul expense must be restated to current dollars supported by any intervening parties in this case?

A. Yes. In his direct testimony, DPU witness Dr. William Powell provides a detailed and astute argument supporting the Company's methodology on this issue in this case.[50] A similar argument was provided in previous dockets, however, based on settlement agreements was not ruled on by this Commission in those cases.

Q. Does the Company still agree with Dr. Powell's conclusion as it relates to the generation overhaul adjustment?

A. Yes. Before averaging historical amounts from different years, it is important that the

[47] Direct Testimony of Donna Ramas at lines 875-940.
[48] Direct Testimony of Robert A. Davis at lines 196-200.
[49] Direct Testimony of Donna Ramas at lines 631-806.
[50] Direct Testimony of Dr. William Powell at lines 25-95.

dollars be correctly stated using constant dollars. Since dollars from different years have different purchasing power, failing to restate each of these dollar levels to a common basis is analogous to comparing apples to oranges and bananas. To ignore an adjustment accounting for the differing purchasing power of dollars in different years is to ignore inflation that has already occurred. Any financial analysis performed by the Company in evaluating investment alternatives by necessity and common sense must consider inflation. Ms. Ramas states that productivity offsets and lessons learned will offset any inflationary drivers.[51] This simplistic assumption is a notion that would be difficult to support by actual data.

Q. Do you agree with Ms. Ramas that inflation associated with generation overhaul expenses can be offset with efficiency improvements?

A. No. Sometimes with new or changing technologies efficiencies can be found. However, the Company has been doing generation overhauls on our units since the plants were constructed and the Company has continuously improved on overhaul execution and process. While we continue to improve on overhaul execution our improvements do not materially impact the increases due to inflation.

Q. As pointed out by Ms. Ramas, the Commission has ruled against the use of escalation to constant dollars in prior cases.[52] Why does the Company think the Commission should reconsider its position?

A. Based on arguments provided in both my direct testimony and that of DPU witness Dr. Powell in this case, the Company urges the Commission to reconsider its position on

[51] Direct Testimony of Donna Ramas at lines 777-796.
[52] *Id.* at lines 712-742.

this issue.

Depreciation on Retired Wind Assets

Q. Please describe how depreciation expense is calculated for the repowered wind assets.

A. In order to calculate depreciation expense, the gross plant in-service ("PIS") balance is multiplied by the applicable depreciation rates. To better illustrate the calculation of depreciation expense with regards to repowered wind assets, I would like to break this into two individual components: the existing equipment that is replaced and the new repowered assets that are added.

Prior to repowering, the existing equipment is included in the gross PIS balance. Accumulated depreciation offsets gross PIS balance and results in net PIS. Depreciation expense is calculated by multiplying the Commission-approved depreciation rate by only the gross PIS balance. Net PIS, or the offset as a result of the accumulated depreciation reserve, does not impact depreciation expense. When retirements occur as a result of repowering, the Company transfers the retired assets from gross PIS to the accumulated depreciation reserve. This can impact depreciation expense as shown in Table 6 below:

TABLE 6

Depreciation Expense Illustration

	Existing Equipment	Retirement	Balance After Retirement	Capital Addition	Final Balance
Gross Plant in Service	$1,000	($1,000)	$0	$1,050	$1,050
Accumulated Depreciation	($250)	$1,000	$750	$0	$750
Net Plant in Service	$750	$0	$750	$1,050	$1,800
Depreciation Rate	5%		5%	5%	5%
Depreciation Expense	$50		$0	$53	$53

Specifically, the example shows that depreciation expense on the existing equipment halts once the retirement occurs. This is because the balance is retired to accumulated depreciation and the new gross PIS balance is zero.

In the event the asset is then repowered, the repowered asset becomes used and useful and is placed in-service. This increases gross PIS. The cumulative balance of each transaction appears in the Final Balance column and illustrates both the retirement and repowering capital addition. Depreciation expense is calculated on the new gross plant balance multiplied by the depreciation rate. It should be noted the example above assumed a five percent depreciation rate, for simplicity.

Q. How is the depreciation rate determined?

A. To determine the depreciation rates for all assets, the Company prepares a depreciation study. The general basis of each depreciation study is to determine a rate at which the net PIS balance reaches zero (absent consideration of any decommissioning and removal costs) at the end of the depreciable life of the asset. When setting a depreciation rate, the net PIS is considered. Once the depreciation rate is established though, the depreciation expense is multiplied only on the gross PIS balance.

Q. Does this mean the calculated depreciation rate accounts for the accumulated depreciation reserve?

A. Yes. One of the assumptions is to fully depreciate the net PIS balance to zero at the end of its depreciable life. In the example above, since the accumulated depreciation reserve increases the net PIS balance, this results in a higher depreciation rate upon adoption of the revised depreciation rates as approved through a depreciation study proceeding.

Q. Were any adjustments proposed by intervening parties in relation to the depreciation rate calculation for repowered wind assets?

A. No intervening party proposed changes to the existing depreciation rates or the rates that were approved by the Commission in Docket No. 18-035-36. DPU witness Mr. Smith did, however, propose two alternative recovery methods for the retired wind assets; accelerate depreciation to match the 10-year PTC eligibility period of the repowered assets or defer PTCs to a regulatory asset and amortize them back over the depreciable life of the asset.[53] Mr. Smith further requests the Company provide an accelerated schedule as part of this filing.[54] The Company has provided an estimated schedule of accelerating the retired wind assets over a ten year life as Exhibit RMP__(SRM-8R). No adjustment for this proposal was captured in the revenue requirement supported by the DPU.

Q. Does the Company accept Mr. Smith's proposal regarding the retired wind assets?

A. Throughout this filing, the Company has continued its efforts to manage rate pressure

[53] Direct Testimony of Gary L. Smith at lines 295-304.
[54] *Id.* at line 166.

which is especially important to customers given the COVID-19 global pandemic. As supported in the rebuttal testimony of Mr. Hoogeveen and Ms. Kobliha, the Company reduced its requested ROE from 10.20% to 9.80% specifically in consideration of the current circumstances. As such, the Company has not included an accelerated depreciation associated with the retired wind in the revised revenue requirement. Although the Company is not opposed to this proposal, the estimated $23 million of increased depreciation expense to accelerate cost recovery in Utah would increase rate pressure for Utah customers. Similarly, deferring PTCs causes concerns for the Company and challenges to standard accounting practices. Historically, PTCs (whether included or excluded from the EBA) are included in base rates under the anticipated amount for the Test Year. Including a total 10-year period of PTCs and amortizing back over 30 years, when the PTCs are not yet received, causes significant concerns. The Company would urge the Commission to reject this proposal.

Q. Please explain the adjustment to the accumulated depreciation reserve proposed by UAE witness Mr. Higgins.

A. Mr. Higgins recommends an adjustment to accumulated depreciation reserve balance on the retired wind assets to account for the depreciation expense currently paid on those assets by Utah customers.[55] Specifically, Mr. Higgins argues that the depreciation expense currently in rates set in the last GRC should be credited (through accumulated depreciation) to customers until the rate effective date of this case.

Q. Does the Company accept Mr. Higgins's proposed adjustment?

A. No. Mr. Higgins's adjustment is inconsistent with normal practice, the remaining

[55] Direct Testimony of Kevin C. Higgins at lines 226-252.

accounting entries related to repowering, and with his position in the repowering Docket No. 17-035-39 ("Repowering Docket"). Mr. Higgins has selected only one component of the repowering accounting and adjusts solely for the changed depreciation expense associated with the retired wind assets, ignoring the offsetting adjustment for increased depreciation expense associated with repowering. This is fundamentally incorrect. As illustrated previously, the Company records depreciation expense on the gross PIS balance. The repowered asset retirements are recorded against the accumulated depreciation reserve, and while he is correct in his assertion that the depreciation expense on these assets would stop, he is not considering the new capital placed in-service related to the retirement. In fact, the Company assumed retirements of $1.3 billion and placed in-service $1.1 billion of capital investments. Because depreciation expense is charged on the gross PIS balance, the depreciation expense following the retirement would be similar to the amount allocated to Utah before the retirement. This was fully explained in the Repowering Docket where the Company proposed a Resource Tracking Mechanism ("RTM") that would have captured both impacts, but which was opposed by UAE in that proceeding and ultimately rejected by the Commission. Furthermore, since customers are not paying depreciation expense on the repowered capital additions that were placed in-service since the last rate case, yet depreciation expense is booked for regulatory and accounting purposes, Utah customers benefit through an accumulated depreciation reserve on those new assets. Including a benefit of accumulated depreciation on both the retired wind asset and repowered wind assets is a double count.

Q. Is this circumstance unique to repowered wind assets?

A. No. In fact this is a common occurrence in utility accounting and is commonly referred to as “regulatory lag.” Regulatory lag is the time between the date a utility incurs the cost associated with a capital project, for example, and when rates are reset to recover these costs. Since the last GRC, Docket No. 13-035-184, which had a rate effective date of September 1, 2014, there have been multiple capital projects completed and placed in-service. Due to regulatory lag, Utah customers are not paying for any assets placed in-service since the last GRC, even as they are receiving the benefits.

Q. Is it true that regulatory lag can also occur with capital that has been retired since the last GRC?

A. Yes, absolutely. Often times a utility will retire an asset that is fully depreciated that could reduce depreciation expense on the Company’s book. Without a GRC to reset customer rates, customers could theoretically pay a rate that was established using depreciation expense based on those retired assets.

Q. Does Mr. Higgins consider regulatory lag in his proposed adjustment?

A. Only selectively. Mr. Higgins does not consider the regulatory lag the Company has experienced since the last GRC, including the regulatory lag associated with repowering. He does, however, consider the portion of the regulatory lag of individual project retirements, specifically those associated with repowering that is beneficial to customers. To properly balance the depreciation expense paid by customers and the assets from which they are receiving benefits, the Company would need a balancing mechanism for the revenue requirement of all capital projects. This is not usually required in the normal course of business as the Company often invests at a rate equal to depreciation expense. In other words, the gross rate base would increase but be offset by accumulated depreciation maintaining a fair return and recovery of costs. This is one tool that has allowed the Company to stay out of a GRC proceeding since 2014. However, when the Company invests in major capital projects such as Energy Vision 2020 or the wind repowering projects, this no longer holds true.

Q. What other concern do you have with Mr. Higgins's proposal?

A. Recently, Mr. Higgins provided testimony in the Repowering Docket that discussed his view of the risk of specific rate treatment in isolation of all other factors, citing a general concern about single-issue ratemaking.[56] His proposed adjustment in this case is in conflict with his single-issue ratemaking concerns, in that he only takes into account the single retirement transaction. His proposal fails to consider all the other factors such as the asset that is placed in-service due to repowering, or even the impact of assets put into service since the last GRC.

Q. Did the Company propose an alternative that would have credited customers with this benefit?

A. Yes. In the Repowering Docket, the direct testimony of Company witness Mr. Jeffrey K. Larsen explained the accounting for the replaced equipment and the impacts on depreciation expense associated with both new equipment and replaced equipment.[57] The Company proposed to include both components in a RTM to fairly match both benefits and costs. In that proceeding, Mr. Higgins stated concerns with the RTM because it was single-issue ratemaking, and that it "brings with it attendant

[56] *In the Matter of the Voluntary Request of Rocky Mountain Power for Approval of Resource Decision to Repower Wind Facilities*, Docket No. 17-035-39, Prefiled Response Testimony of Kevin C. Higgins at lines 1022-1024 (April 2, 2018).
[57] *Id.*, Direct Testimony of Jeffrey K. Larsen at lines 193-208 (June 30, 2017).

concerns about the efficacy of identifying costs and setting rates in isolation."[58] In this proceeding, Mr. Higgins proposes to carve out a small portion of what the Company had proposed for the RTM. He attempts to isolate this small component related to capital that provides a benefit, ignoring the bigger picture of the project economics. Here, Mr. Higgins's proposal would have larger impacts than would the RTM, because it asymmetrically gives customers the benefits of the decrease in depreciation expense associated with replaced equipment without a corresponding payment from customers for the additional costs associated with the new assets.

Q. Mr. Higgins also proposes that a 200 basis point reduction is the appropriate return on the retired wind assets approved in the Repowering Docket.[59] Would you like to address this?

A. Yes. Mr. Higgins states that this adjustment was "to ensure that the Company and customers are reasonably sharing risks and benefits…"[60] I disagree with this logic on several points. First, the Company made a prudent decision for customers. The benefits from the decision will entirely flow to customers. The Company is recovering its costs, including its cost of capital. Second, I have an issue with this logic in that he is asking the Commission to evaluate a sharing of risks and reducing the Company's capital cost recovery. The Company's return on equity was addressed by Ms. Bulkley and the capital structure was addressed by Ms. Kobliha in the capital cost recovery portion of this proceeding. Both witnesses analyzed the Company's cost of capital, including both the return on equity and the capital structure, on a total Company basis. Here, Mr.

[58] *Id.,* Direct Testimony of Kevin C. Higgins at lines 101-102 (April 2, 2018).
[59] *Id.,* at lines 778-797.
[60] *Id.*, at lines 999-1000.

Higgins is trying to isolate one component and reduce the return on component without looking at the impact it would have on the return of the total Company or the impact on capital structure. This is something that would have been better addressed in the cost of capital phase of this case, in which UAE did not submit testimony. If the looming question is about a reasonable return that is allowed for customers, I would refer to the testimonies of Company witnesses Ms. Bulkley and Ms. Kobliha.

Q. Did Mr. Higgins ever challenge the prudency of these retired wind assets?

A. No. Mr. Higgins never provides testimony challenging the overall prudence or the economic analysis Mr. Link supported to pursue these investments, he simply recommends an unsupported disallowance. The Company would urge the Commission to reject his proposal. I will also mention, when these wind assets were originally built, the Company procured funding using the capital structure. Today, these assets are still financed using a blend of debt and equity as they have not been fully recovered.

Lake Side 2 and Blundell Outage Capital Costs

Q. Have any changes been made to the revised revenue requirement as a result of the Lake Side or Blundell outages?

A. No. The revised revenue requirement does not include the removal of any costs related to the outages at Lake Side 2 Unit 3 or Blundell Unit 2. Further support for the prudency of these outages is provided in the rebuttal testimony of Mr. Dana Ralston.

Excess Deferred Income Taxes EDIT

Q. Please describe the Tax Cuts and Jobs Act ("TCJA").

A. On December 22, 2017, Congress passed and the President signed the TCJA which, most notably, set a new corporate income tax rate of 21 percent compared to the previous rate of 35 percent.[61] As a result of this change, certain deferred income taxes were restated as excess deferred income taxes EDIT and classified as protected property, non-protected property, and non-protected non–property. Each of the non-protected EDIT balances were available immediately and can be returned to customers. The protected property EDIT relates to specific assets and is returned to customers using the RSGM. The RSGM amortizes these balances back to customers using a straight-line basis over the remaining regulatory life of that specific asset. Although different, the amortization of EDIT works much like that of Accumulated Deferred Income Taxes ("ADIT"). I will note that the Company has deferred balances associated with protected property EDIT RSGM amortization for 2018, 2019, and estimated 2020 that is available to be returned to customers. I will refer to this as non-protected EDIT.

Q. What was the Company's proposal to refund the non-protected EDIT balances?

A. The Company proposed to refund the non-protected EDIT balances via a variety of rate mitigation efforts and through a two-year amortization Schedule 197 sur-credit.

Q. Did any party propose any changes to the Company's treatment of the non-protected EDIT balances?

A. OCS witness Ms. Ramas has proposed three changes: (1) to use a small portion of these funds to buy-down the remaining balance of the Craig and Hayden electric plant acquisition adjustment that was discussed previously in my testimony,[62] (2) to revise the Deer Creek Mine that was included as part of a rate mitigation effort,[63] and (3) to return to customers the remaining balances as part of base rates using a ten-year

[61] Pub. L. No. 115-97 (Dec. 22, 2017).
[62] Direct Testimony of Donna Ramas at lines 1530-1551.
[63] *Id.* at lines 1395-1456.

amortization.[64]

Q. Does the Company accept Ms. Ramas's proposals?

A. The Company has accepted the buy-down of the electric plant acquisition adjustment for the Craig and Hayden plants and a portion of her revision to the Deer Creek Mine. Although the Company is not opposed to a different amortization period, it continues to recommend returning the remaining TCJA balances through Schedule 197. No changes from the original filing related to amortization were reflected in this filing.

Q. Please further describe the proposed changes related to the Deer Creek Mine?

A. OCS witness Ms. Ramas proposed two changes be incorporated into the revised revenue requirement for the Deer Creek Mine: 1) remove the carrying charges that were accrued on the unpaid recovery royalties, and 2) remove the recovery royalties from closure costs.[65]

Q. You mentioned you have accepted a portion of the changes related to the Deer Creek Mine proposed by Ms. Ramas, can you explain?

A. Yes. Through a workpaper provided by the Company in response to data request OCS 7.2, Ms. Ramas identified an oversight with the calculation of the carrying charge. Specifically, a carrying charge was included on recovery royalties, which are not yet paid. Ms. Ramas recommends the carrying associated with these recovery royalties be excluded from the carrying charge calculation. The Company agrees with Ms. Ramas' proposal on carrying charges and has reflected that revision accordingly.

Q. Please describe recovery-based royalties.

A. The Department of Interior's Office of Natural Resources Revenue ("ONRR") requires

[64] *Id.* at lines 1810-1833.
[65] *Id.* at lines 1395-1456.

royalty payments on recoverable costs for coal production, mine closure and final reclamation activities. The Company does not have a specific timeline of when actual royalty obligations will be settled with the ONRR, but the majority of expenditures associated with mine closure and reclamation have been incurred.

Q. Are recovery-based royalties included in this filing considered final?

A. No. Due to project delays, the Company still considers the royalties included in this case to be preliminary. In fact, the Company acknowledged certain changes to recovery-based royalties in its response to data request OCS 7.5. The Company's most recent estimate of these royalties is $6.7 million, Utah-allocated. This amount has been updated and included as part of this filing.

Q. Why should the Commission approve the Company's recommendation to include recovery-based royalties?

A. The Deer Creek Mine was closed in 2014, nearly seven years ago, and nearly all final reclamation activities have been completed. Deferring recovery-based royalties for consideration in a future GRC simply continues to 'kick the can down the road.' This causes intergenerational equity problems by putting the burden of past costs on future ratepayers.

Q. What is the impact of the Deer Creek Mine changes?

A. Since the remaining Utah-allocated share of Deer Creek Mine costs were included as part of a rate mitigation effort, the changes of both the carrying charge and the recovery-based royalties do not impact the revised revenue requirement. The Company continues to support a rate mitigation effort to buy-down, or fully recover, these costs using non-protected EDIT balances. Since the rate mitigation proposals were largely unchallenged by intervening parties, the only change to reflect these updates was to revise the total available balance available to refund to customers via a Schedule 197 sur-credit. A summary of these revisions has been included as Table 7 below:

TABLE 7

TCJA Comparison

$ - Millions

	Original	Rebuttal	Difference
Total Deferred EDIT Balances	(142.6)	(142.6)	-
Total Deferred Non-EDIT Tax Benefits	(1.5)	(1.5)	-
Total Deferred Tax Benefits	(144.0)	(144.0)	-
Dave Johnston Buy-Down	23.9	23.9	-
2017 Protocol Regulatory Asset	13.2	13.2	-
EIM Benefit Regulatory Asset	9.6	9.6	-
Carbon Regulatory Assets	10.3	10.3	-
Deer Creek Regulatory Assets	20.6	21.7	1.1
Electric Plant Acquisition Adjustment	-	2.7	2.7
Total Amount Used/Rate Mitigation	77.5	81.4	3.8
			-
Remaining Deferred Tax Benefits (excl. Interest)	(66.5)	(62.7)	3.8

Additional details, including the calculation of the sur-credit and applicable carrying charge, have been provided as Exhibit RMP__(SRM-5R).

Q. Would you like to address anything else on EDIT?

A. I would like to address one more recommendation made by Ms. Ramas related to protected property EDIT RSGM amortization. Ms. Ramas suggested the Company continue to defer the difference between the amount set in rates through this proceeding and the actual RSGM amortization.[66] As mentioned earlier, the EDIT works much like the ADIT and follows specific assets and while the Company is currently deferring this amount annually, that is simply due to the timing of the tax law change. The Company's

[66] Direct Testimony of Donna Ramas at lines 1705-1721.

last rate case where base rates were reset was prior to the tax law change and resulted in the Commission addressing this issue in Docket No. 17-035-69. I believe the intent was to always fully implement the tax law change into rates as part of this rate case. Additionally, to isolate only one component of the revenue requirement and require tracking would not accurately capture and reflect the year to year changes on those assets. One reason Ms. Ramas cites for the deferral is that "[t]he amount of amortization was much higher in 2020 due in part to the retirement of Cholla."[67] This statement is factually accurate. However, Cholla was a plant closure and the change in RSGM was a small part of the impact of closing Cholla. In similar types of situations, the Commission should look at all closure costs for deferral without isolating RSGM only. Therefore the Company does not agree with Ms. Ramas's proposal, unless a tracking mechanism were to be established for all revenue requirement components.

Craig Unit 2 Selective Catalytic Reduction ("SCR")

Q. Please describe the Company's investment in the Craig Unit 2 SCR.

A. As described in the direct testimony of Mr. James C. Owen, the Company was responsible under the terms of the Participation Agreement to pay for its joint owner share of the investment in the Craig Unit 2 SCR.

Q. Have any adjustments been proposed for recovery of this investment?

A. Mr. Higgins proposes that because the Company's analysis did not support the investment in the SCR, the Commission should reduce the Company's return on this asset to the cost of long-term debt plus a tax gross up factor.[68]

[67] Direct Testimony of Donna Ramas at lines 1712-1714.
[68] Direct Testimony of Kevin C. Higgins at lines 1095-1113.

Q. Does the Company agree with Mr. Higgins' proposal?

A. No. In Mr. Owen's direct testimony, he supports the overall prudence of the project and explains how this investment results in customer benefits. Furthermore, the Company, as with all of its capital investment projects, financed this project under the Company's capital structure. To limit the return of this asset to only the cost of long-term debt plus a tax gross up does not provide a fair return on the shareholder dollars used as part of the financing of the project.

Cholla Unit 4

Q. Please summarize the Company's proposed adjustment in regards to Cholla Unit 4.

A. As previously mentioned in my direct testimony, the Company proposes to buy-down, on December 31, 2020, the remaining net plant balance of Cholla Unit 4 using the Sustainable Transportation and Energy Plan funds, as agreed to in the settlement in Docket No. 17-035-69. This buy-down includes balances associated with closure costs such as construction work in progress, obsolete M&S inventory, liquidated damages, and the estimated decommissioning cost.

Q. Did any party propose changes to closure costs associated with the Cholla Unit 4 generating plant?

A. UAE witness Mr. Higgins proposed two changes to the closure costs; the removal of construction work-in-progress ("CWIP") and the removal of estimated obsolete M&S inventory.[69]

[69] Direct Testimony of Kevin C. Higgins at lines 463-490.

Q. Please describe Mr. Higgins's proposal on CWIP.

A. Mr. Higgins proposed that the Commission deny the Company's proposal to include canceled CWIP projects as part of overall closure costs as they are not used and useful to customers.

Q. Does the Company agree with this proposal?

A. No. As part of normal maintenance or changes in load, the Company regularly spends capital dollars on generation assets. The projects included in CWIP were in construction prior to the decision to close the facility. Once the decision was made to close, the Company prudently stopped all in-progress and future capital projects for Cholla Unit 4. Under different circumstances, these projects would have been completed and moved from CWIP to Electric Plant in-service. However, since the Company stopped capital spend on the in-progress projects in CWIP, he suggests the Company should not get recovery. While I agree that these projects may not have been used and useful in the traditional sense, I would note that had the Company continued operation of Cholla Unit 4, customers would have been harmed by the Company not pursuing these prudent and economic projects. In other words, to penalize the Company for making a prudent and economic decision only creates a disincentive for pursuing future economic solutions.

Q. Do you have anything else to add related to CWIP?

A. Yes. When the Company included the amount of CWIP for purposes of the original filing, there was an estimated $1.8 million balance. It was later determined that $526 thousand of the total balance was related to an accrual or estimate of what was expected to be billed by Arizona Public Service for work on projects that were wrapping up. These projects were classified as "technically complete" and moved out of CWIP and into Electric Plant in-service in December 2019.

Q. Did the Company make an adjustment for this reclassification?

A. No. The reclassification of $526 thousand would have resulted in a smaller CWIP balance and corresponding larger amount of unrecovered plant. The Company has not proposed an adjustment, because the net result of this transaction would result in the same overall recovery initially proposed by the Company. However, if the proposed CWIP adjustment is adopted the CWIP balance should be reduced to $1.3 million.

Q. Please describe Mr. Higgins's proposal on obsolete M&S Inventory.[70]

A. Mr. Higgins makes a similar proposal for obsolete M&S inventory to his proposal for CWIP, in that he asserts the obsolete M&S inventory is not used and useful to customers. The Company acquires M&S inventory for use in construction, operations, and maintenance purposes and is often specific to the equipment in which that inventory supports. An example of this inventory can include spare parts that may be needed to complete the repair in the event of an outage. The Company reports the balances associated with M&S inventory in FERC account 154 and includes these balances in rate base.

Q. Do you agree with Mr. Higgins's proposed adjustment?

A. No. The balances associated with obsolete M&S inventory should be treated similarly to the unrecovered plant balance. This inventory is included in rate base and has been used and useful because these assets were used to support the ongoing operations of the plant. Since the M&S has now been deemed obsolete based on the decision to

[70] Direct Testimony of Kevin C. Higgins at lines 463-490.

pursue an economically beneficial decision simply penalizes and disincentivizes the Company for pursuing these least cost, economic solutions.

Pension Balancing Account

Q. Please describe the pension balancing account alternative.

A. As addressed in the rebuttal testimony of Ms. Kobliha, the Company offers a pension balancing account alternative to alleviate the overall concern in accurately projecting pension and pension settlement costs. Furthermore, this proposal would ensure that customers only pay actual incurred pension and pension settlement expense and any differences would be trued up in a future GRC.

Q. If the Commission adopts the pension expense balance account, how would the Company propose it be implemented?

A. The Company would not propose to make any changes to the pension expense or pension settlement that was included in the original filing. Instead, the amount collected from customers, beginning with the rate effective date of this case, would be isolated. Differences between actual pension expense and the amount collected from customers would be booked to a regulatory asset or regulatory liability account.

Q. How does the Company propose to collect or refund any differences between actual pension expense and pension settlement and the amount collected from customers?

A. The Company is proposing to only track the differences between actual pension and pension settlement expense and the amount paid by customers as part of a regulatory liability or regulatory asset. This regulatory asset or regulatory liability balance would be included in rate base and reported as part of the Results of Operations report that is filed twice per year. The Company would then make a proposal to either collect or refund the regulatory asset/liability balance in the next GRC.

Q. Has a similar balancing account ever been proposed by the Company?

A. Yes. I previously identified a change to the captive insurance policy and a similar balancing account that has been used by the Company. This treatment would also work similarly to that proposed by Ms. Ramas for REC revenues[71] and the pension expenses proposed by the Company.

RATE MITIGATION AND SCHEDULE 197

Q. Please summarize the changes the Company has made to the rate mitigation proposals set forth in its original filing.

A. Three changes to rate mitigation proposals were made as part of the revised revenue requirement: 1) the buy-down of the Craig and Hayden electric plant acquisition adjustment, (2) the revision of Deer Creek to include updated recovery-based royalties and, (3) the exclusion of interest on Deer Creek Recovery-royalties. As a result of these changes, the Company is now proposing to amortize the remaining TCJA benefits of $62.7 million over two years through Schedule 197. After inclusion of interest, approximately $38.2 million would be returned in 2021 and $26.8 million in 2022. Additional details on this calculation are provided as Exhibit RMP__(SRM-5R). The sur-credit would expire on January 1, 2023.

Other Items

Q. Are there any other items you would like to mention?

A. In reviewing the intervening parties' workpapers, the Company noticed that the

[71] Direct Testimony of Donna Ramas at lines 272-287.

revenue requirement adjustments did not always include changes that are circular in nature. For example, if an adjustment is made to a plant based FERC account, that adjustment could also have an impact to certain plant based allocation factors such as the System Overhead factor. These changes would then also change the overall synchronization of cash working capital and interest. Although the changes are small, they should be noted and corrected in the Commission's order in this proceeding.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Rocky Mountain Power
Exhibit RMP___(SRM-1R)
Docket No. 20-035-04
Witness: Steven R. McDougal

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Steven R. McDougal

Summary - Utah - Allocated Results of Operations

October 2020

Rocky Mountain Power
UTAH
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 2021

(1)	Test Period 2020 Protocol Revenue Requirement	2,073,745,852	Page 1.1
(2)	Normalized General Business Revenues	2,001,695,945	Page 1.1
(3)	2020 Protocol Price Change	**72,049,907**	Page 1.1

Rocky Mountain Power
UTAH
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 2021

	(1) Total Adjusted Results	(2) Jan. 1, 2021 Price Change	(3) Results with Price Change	(4) Jul. 1, 2021 Price Change	(5) Results with Price Change
1 Operating Revenues:					
2 General Business Revenues	2,001,695,945	49,511,653	2,051,207,598	22,538,254	2,073,745,852
3 Interdepartmental	-				
4 Special Sales	112,151,329				
5 Other Operating Revenues	75,210,750				
6 Total Operating Revenues	2,189,058,024				
7					
8 Operating Expenses:					
9 Steam Production	397,319,710				
10 Nuclear Production	-				
11 Hydro Production	20,497,691				
12 Other Power Supply	442,281,907				
13 Transmission	95,890,672				
14 Distribution	92,477,865				
15 Customer Accounting	34,769,928	96,311	34,866,239	43,842	34,910,081
16 Customer Service & Info	6,902,035				
17 Sales	-				
18 Administrative & General	55,938,610				
19					
20 Total O&M Expenses	1,146,078,418				
21					
22 Depreciation	433,162,280				
23 Amortization	4,382,255				
24 Taxes Other Than Income	90,220,630	148,535	90,369,165	67,615	90,436,779
25 Income Taxes - Federal	(63,123,244)	9,876,320	(53,246,924)	4,495,810	(48,751,114)
26 Income Taxes - State	3,849,028	2,236,713	6,085,741	1,018,177	7,103,917
27 Income Taxes - Def Net	50,161,171				
28 Investment Tax Credit Adj.	(1,117,294)				
29 Misc Revenue & Expense	212,024				
30					
31 Total Operating Expenses:	1,663,825,268	12,357,879	1,676,183,147	5,625,444	1,681,808,591
32					
33 Operating Rev For Return:	525,232,756	37,153,774	562,386,530	16,912,810	579,299,340
34					
35 Rate Base:					
36 Electric Plant In Service	13,702,391,432				
37 Plant Held for Future Use	6,357,564				
38 Misc Deferred Debits	258,987,500				
39 Elec Plant Acq Adj	11,116,608				
40 Pensions	15,189,809				
41 Prepayments	16,439,455				
42 Fuel Stock	74,344,484				
43 Material & Supplies	101,315,658				
44 Working Capital	13,410,124				
45 Weatherization Loans	(1)				
46 Misc Rate Base	-				
47					
48 Total Electric Plant:	14,199,552,634	-	14,199,552,634	-	14,199,552,634
49					
50 Rate Base Deductions:					
51 Accum Prov For Deprec	(4,183,178,675)				
52 Accum Prov For Amort	(276,093,963)				
53 Accum Def Income Tax	(1,164,479,247)				
54 Unamortized ITC	(84,977)				
55 Customer Adv For Const	(38,042,160)				
56 Customer Service Deposits	(16,275,584)				
57 Misc Rate Base Deductions	(775,784,172)				
58					
59 Total Rate Base Deductions	(6,453,938,778)	-	(6,453,938,778)	-	(6,453,938,778)
60					
61 Total Rate Base:	7,745,613,856	-	7,745,613,856	-	7,745,613,856
62					
63 Return on Rate Base	6.781%		7.261%		7.479%
64					
65 Return on Equity	8.499%		9.393%		9.800%
66					
67 TAX CALCULATION:					
68 Operating Revenue	515,002,417	49,266,806	564,269,224	22,426,797	586,696,021
69 Other Deductions					
70 Interest (AFUDC)	(20,261,623)	-	(20,261,623)	-	(20,261,623)
71 Interest	168,672,646	-	168,672,646	-	168,672,646
72 Schedule "M" Additions	517,841,906	-	517,841,906	-	517,841,906
73 Schedule "M" Deductions	799,652,955	-	799,652,955	-	799,652,955
74 Income Before Tax	84,780,344	49,266,806	134,047,151	22,426,797	156,473,948
75					
76 State Income Taxes	3,849,028	2,236,713	6,085,741	1,018,177	7,103,917
77 Taxable Income	80,931,317	47,030,093	127,961,410	21,408,620	149,370,031
78					
79 Federal Income Taxes + Other	(63,123,244)	9,876,320	(53,246,924)	4,495,810	(48,751,114)

Ref. Page 2.0

Rocky Mountain Power
UTAH
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 2021

Net Rate Base	$	7,745,613,856	Ref. Page 1.1
Return on Rate Base Requested		7.48%	Ref. Page 2.1
Revenues Required to Earn Requested Return		579,299,340	Ref. Page 1.1
Less Current Operating Revenues		(525,232,756)	Ref. Page 1.1
Increase to Current Revenues		54,066,584	
Net to Gross Bump-up		133.26%	
Price Change Required for Requested Return	$	72,049,907	Ref. Page 1.1
Requested Price Change	$	72,049,907	
Uncollectible Percent		0.195%	Ref. Page 1.3
Increased Uncollectible Expense	$	140,153	
Requested Price Change	$	72,049,907	
Franchise Tax		0.000%	Ref. Page 1.3
Revenue Tax		0.000%	Ref. Page 1.3
Resource Supplier Tax		0.000%	Ref. Page 1.3
PUC Fees Based on General Business Revenues		0.300%	Ref. Page 1.3
Increase Taxes Other Than Income	$	216,150	
Requested Price Change	$	72,049,907	
Uncollectible Expense		(140,153)	Ref. Page 1.1
Taxes Other Than Income		(216,150)	
Income Before Taxes	$	71,693,603	
State Effective Tax Rate		4.54%	Ref. Page 2.0
State Income Taxes	$	3,254,890	
Taxable Income	$	68,438,714	
Federal Income Tax Rate		21.00%	Ref. Page 2.0
Federal Income Taxes	$	14,372,130	
Operating Income		100.000%	
Net Operating Income		75.040%	Ref. Page 1.3
Net to Gross Bump-Up		133.26%	

Rocky Mountain Power
UTAH
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 2021

Operating Revenue	100.000%	
Operating Deductions		
Uncollectible Accounts	0.195%	See Note (1) Below
Taxes Other - Franchise Tax	0.000%	
Taxes Other - Revenue Tax	0.000%	
Taxes Other - Resource Supplier	0.000%	
PUC Fees Based on General Business Revenues	0.300%	
Sub-Total	99.505%	
State Income Tax @ 4.54%	4.518%	
Sub-Total	94.988%	
Federal Income Tax @ 21.00%	19.947%	
Net Operating Income	75.040%	

(1) Uncollectible Accounts =	3,893,752	Pg 2.11, UTAH Situs from Account 904
	2,001,695,945	Pg. 2.2, General Business Revenues

Rocky Mountain Power
Utah General Rate Case - December 2021
Adjustment Summary
REDACTED

	UTAH ALLOCATED UNADJUSTED RESULTS DECEMBER 2019	Tab 3 Revenue Adjustments	Tab 4 O&M Adjustments	Tab 5 Net Power Cost Adjustments	Tab 6 Depreciation & Amortization Adjustments
1 Operating Revenues:					
2 General Business Revenues	1,988,715,510	[redacted]	-	-	[redacted]
3 Interdepartmental	-		-	-	
4 Special Sales	78,282,917		-	19,971,538	
5 Other Operating Revenues	70,101,388		(2,716,081)	-	
6 Total Operating Revenues	2,137,099,816		(2,716,081)	19,971,538	
7					
8 Operating Expenses:					
9 Steam Production	451,142,931	[redacted]	4,095,700	(48,916,477)	[redacted]
10 Nuclear Production	-		-	-	
11 Hydro Production	19,409,835		1,085,315	-	
12 Other Power Supply	462,939,589		3,078,293	(32,724,991)	
13 Transmission	96,044,207		1,718,141	394,121	
14 Distribution	85,455,009		6,529,192	-	
15 Customer Accounting	33,249,315		2,449,447	-	
16 Customer Service & Info	6,511,449		477,757	-	
17 Sales	-		-	-	
18 Administrative & General	50,747,835		4,769,224	-	
19					
20 Total O&M Expenses	1,205,500,169	[redacted]	24,203,069	(81,247,348)	[redacted]
21					
22 Depreciation	305,190,671	[redacted]	-	-	[redacted]
23 Amortization	20,768,321		-	63,742	
24 Taxes Other Than Income	71,685,583		-	-	
25 Income Taxes - Federal	78,802,378		(5,649,060)	20,130,118	
26 Income Taxes - State	20,624,126		(1,279,356)	4,558,914	
27 Income Taxes - Def Net	(11,875,493)		-	176,664	
28 Investment Tax Credit Adj.	(2,284,953)		-	-	
29 Misc Revenue & Expense	(1,588,348)		1,119,232	-	
30					
31 Total Operating Expenses:	1,686,822,455	[redacted]	18,393,885	(56,317,910)	[redacted]
32					
33 Operating Rev For Return:	450,277,361	[redacted]	(21,109,966)	76,289,447	[redacted]
34					
35 Rate Base:					
36 Electric Plant In Service	12,242,571,339	[redacted]	-	1,759,900	[redacted]
37 Plant Held for Future Use	11,265,782		-	-	
38 Misc Deferred Debits	332,552,084		-	-	
39 Elec Plant Acq Adj	17,635,536		-	-	
40 Pensions	1,950,836		-	-	
41 Prepayments	16,466,051		-	-	
42 Fuel Stock	72,830,126		-	-	
43 Material & Supplies	104,244,001		-	-	
44 Working Capital	24,419,769		192,548	(630,413)	
45 Weatherization Loans	2,304		-	-	
46 Misc Rate Base	-		-	-	
47					
48 Total Electric Plant:	12,823,937,828	[redacted]	192,548	1,129,487	[redacted]
49					
50 Rate Base Deductions:					
51 Accum Prov For Deprec	(4,060,488,632)	[redacted]	-	-	[redacted]
52 Accum Prov For Amort	(254,122,375)		-	(34,527)	
53 Accum Def Income Tax	(1,787,640,626)		(162,058)	(197,769)	
54 Unamortized ITC	(115,230)		-	-	
55 Customer Adv For Const	(31,278,618)		-	-	
56 Customer Service Deposits	-		-	-	
57 Misc Rate Base Deductions	(241,470,701)		6,309,806	-	
58					
59 Total Rate Base Deductions	(6,375,116,182)	[redacted]	6,147,748	(232,295)	[redacted]
60					
61 Total Rate Base:	6,448,821,646	[redacted]	6,340,296	897,191	[redacted]
62					
63 Return on Rate Base	6.982%	[redacted]	-0.334%	1.181%	[redacted]
64					
65 Return on Equity	8.857%	[redacted]	-0.623%	2.200%	[redacted]
66					
67 TAX CALCULATION:					
68 Operating Revenue	535,543,420	[redacted]	(28,038,382)	101,155,143	[redacted]
69 Other Deductions					
70 Interest (AFUDC)	(32,072,175)	[redacted]	-	-	[redacted]
71 Interest	140,487,434		141,261	19,989	
72 Schedule "M" Additions	506,676,468		-	63,742	
73 Schedule "M" Deductions	479,528,727		-	782,277	
74 Income Before Tax	454,275,902		(28,179,643)	100,416,619	
75					
76 State Income Taxes	20,624,126	[redacted]	(1,279,356)	4,558,914	[redacted]
77 Taxable Income	433,651,776		(26,900,287)	95,857,704	
78					
79 Federal Income Taxes + Other	78,802,378	[redacted]	(5,649,060)	20,130,118	[redacted]
APPROXIMATE PRICE CHANGE	61,934,348	[redacted]	28,786,069	(101,578,361)	[redacted]

Rocky Mountain Power
Utah General Rate Case - December 2021
Adjustment Summary
REDACTED

	Tab 7	Tab 8	Tab 10	UT Allocated
	Tax Adjustments	Rate Base Adjustments	Rebuttal Adjustments	Results of Operations December 2021
1 Operating Revenues:				
2 General Business Revenues	-	-	-	[redacted]
3 Interdepartmental	-	-	-	[redacted]
4 Special Sales	-	-	(61,532)	[redacted]
5 Other Operating Revenues	-	-	1,685,955	[redacted]
6 Total Operating Revenues	-	-	1,624,423	[redacted]
7				
8 Operating Expenses:				
9 Steam Production	-	(10,617,592)	2,591,195	[redacted]
10 Nuclear Production	-	-	-	[redacted]
11 Hydro Production	-	-	(144,391)	[redacted]
12 Other Power Supply	-	8,771,738	317,047	[redacted]
13 Transmission	-	-	(2,128,947)	[redacted]
14 Distribution	-	-	503,836	[redacted]
15 Customer Accounting	-	-	(571,359)	[redacted]
16 Customer Service & Info	-	-	(55,943)	[redacted]
17 Sales	-	-	-	[redacted]
18 Administrative & General	-	-	1,327,489	[redacted]
19				
20 Total O&M Expenses	-	(1,845,854)	1,838,928	[redacted]
21				
22 Depreciation	-	50,838,862	(1,099,066)	[redacted]
23 Amortization	-	4,268,426	(2,958,845)	[redacted]
24 Taxes Other Than Income	14,331,400	-	4,203,647	[redacted]
25 Income Taxes - Federal	(86,388,387)	(70,785,634)	6,696,442	[redacted]
26 Income Taxes - State	(3,062,690)	(16,030,987)	381,796	[redacted]
27 Income Taxes - Def Net	(4,677,906)	65,825,921	(1,879,644)	[redacted]
28 Investment Tax Credit Adj.	1,167,659	-	-	[redacted]
29 Misc Revenue & Expense	-	681,136	4	[redacted]
30				
31 Total Operating Expenses:	(78,629,924)	32,951,870	7,183,261	[redacted]
32				
33 Operating Rev For Return:	78,629,924	(32,951,870)	(5,558,838)	[redacted]
34				
35 Rate Base:				
36 Electric Plant In Service	-	1,518,727,672	(60,667,479)	[redacted]
37 Plant Held for Future Use	-	(4,908,218)	-	[redacted]
38 Misc Deferred Debits	-	(73,204,422)	(360,162)	[redacted]
39 Elec Plant Acq Adj	-	(4,810,804)	(1,708,124)	[redacted]
40 Pensions	-	13,273,757	(34,785)	[redacted]
41 Prepayments	-	-	(26,595)	[redacted]
42 Fuel Stock	-	1,514,358	-	[redacted]
43 Material & Supplies	-	(2,932,863)	4,521	[redacted]
44 Working Capital	(837,303)	(1,214,406)	478,785	[redacted]
45 Weatherization Loans	-	(2,305)	0	[redacted]
46 Misc Rate Base	-	-	-	[redacted]
47				
48 Total Electric Plant:	(837,303)	1,446,442,770	(62,313,840)	[redacted]
49				
50 Rate Base Deductions:				
51 Accum Prov For Deprec	-	83,718,740	(570,046)	[redacted]
52 Accum Prov For Amort	-	526,101	396,057	[redacted]
53 Accum Def Income Tax	668,586,992	(59,478,549)	13,072,433	[redacted]
54 Unamortized ITC	30,253	-	-	[redacted]
55 Customer Adv For Const	-	(6,763,542)	-	[redacted]
56 Customer Service Deposits 57	-	(16,275,584)	-	[redacted]
Misc Rate Base Deductions 58	(574,605,644)	30,323,848	3,658,519	[redacted]
59 Total Rate Base Deductions				
60	94,011,601	32,051,014	16,556,963	[redacted]
61 Total Rate Base:				
62	93,174,298	1,478,493,784	(45,756,877)	[redacted]
63 Return on Rate Base				
64	1.131%	-2.110%	-0.032%	[redacted]
65 Return on Equity				
66	2.107%	-3.931%	-0.059%	[redacted]
67 TAX CALCULATION:				
68 Operating Revenue				
69 Other Deductions	(14,331,400)	(53,942,570)	(360,244)	[redacted]
70 Interest (AFUDC)				
71 Interest	11,744,704	-	65,848	[redacted]
72 Schedule "M" Additions	2,075,916	32,940,723	(1,004,881)	[redacted]
73 Schedule "M" Deductions	(57,404,777)	84,064,242	(5,016,935)	[redacted]
74 Income Before Tax	(18,096,674)	350,286,385	(12,847,759)	[redacted]
75	(67,460,124)	(353,105,435)	8,409,613	[redacted]
76 State Income Taxes				
77 Taxable Income	(3,062,690)	(16,030,987)	381,796	[redacted]
78	(64,397,434)	(337,074,449)	8,027,817	[redacted]
79 Federal Income Taxes + Other				
	(86,388,387)	(70,785,634)	6,696,442	[redacted]
APPROXIMATE PRICE CHANGE	(95,224,564)	195,693,205	(23,736,554)	[redacted]

Rocky Mountain Power
Exhibit RMP___(SRM-2R)
Docket No. 20-035-04
Witness: Steven R. McDougal

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Steven R. McDougal

Test Period Results of Operations - Twelve Month Ending December 2021

October 2020

Rocky Mountain Power
UTAH
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 2021

(1)	Test Period 2020 Protocol Revenue Requirement	2,073,745,852	Page 1.1
(2)	Normalized General Business Revenues	2,001,695,945	Page 1.1
(3)	2020 Protocol Price Change	**72,049,907**	Page 1.1

Rocky Mountain Power
UTAH
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 2021

		(1) Total Adjusted Results	(2) Jan. 1, 2021 Price Change	(3) Results with Price Change	(4) Jul. 1, 2021 Price Change	(5) Results with Price Change
1	Operating Revenues:					
2	General Business Revenues	2,001,695,945	49,511,653	2,051,207,598	22,538,254	2,073,745,852
3	Interdepartmental	-				
4	Special Sales	112,151,329				
5	Other Operating Revenues	75,210,750				
6	Total Operating Revenues	2,189,058,024				
7						
8	Operating Expenses:					
9	Steam Production	397,319,710				
10	Nuclear Production	-				
11	Hydro Production	20,497,691				
12	Other Power Supply	442,281,907				
13	Transmission	95,890,672				
14	Distribution	92,477,865				
15	Customer Accounting	34,769,928	96,311	34,866,239	43,842	34,910,081
16	Customer Service & Info	6,902,035				
17	Sales	-				
18	Administrative & General	55,938,610				
19						
20	Total O&M Expenses	1,146,078,418				
21						
22	Depreciation	433,162,280				
23	Amortization	4,382,255				
24	Taxes Other Than Income	90,220,630	148,535	90,369,165	67,615	90,436,779
25	Income Taxes - Federal	(63,123,244)	9,876,320	(53,246,924)	4,495,810	(48,751,114)
26	Income Taxes - State	3,849,028	2,236,713	6,085,741	1,018,177	7,103,917
27	Income Taxes - Def Net	50,161,171				
28	Investment Tax Credit Adj.	(1,117,294)				
29	Misc Revenue & Expense	212,024				
30						
31	Total Operating Expenses:	1,663,825,268	12,357,879	1,676,183,147	5,625,444	1,681,808,591
32						
33	Operating Rev For Return:	525,232,756	37,153,774	562,386,530	16,912,810	579,299,340
34						
35	Rate Base:					
36	Electric Plant In Service	13,702,391,432				
37	Plant Held for Future Use	6,357,564				
38	Misc Deferred Debits	258,987,500				
39	Elec Plant Acq Adj	11,116,608				
40	Pensions	15,189,809				
41	Prepayments	16,439,455				
42	Fuel Stock	74,344,484				
43	Material & Supplies	101,315,658				
44	Working Capital	13,410,124				
45	Weatherization Loans	(1)				
46	Misc Rate Base	-				
47						
48	Total Electric Plant:	14,199,552,634	-	14,199,552,634	-	14,199,552,634
49						
50	Rate Base Deductions:					
51	Accum Prov For Deprec	(4,183,178,675)				
52	Accum Prov For Amort	(276,093,963)				
53	Accum Def Income Tax	(1,164,479,247)				
54	Unamortized ITC	(84,977)				
55	Customer Adv For Const	(38,042,160)				
56	Customer Service Deposits	(16,275,584)				
57	Misc Rate Base Deductions	(775,784,172)				
58						
59	Total Rate Base Deductions	(6,453,938,778)	-	(6,453,938,778)	-	(6,453,938,778)
60						
61	Total Rate Base:	7,745,613,856	-	7,745,613,856	-	7,745,613,856
62						
63	Return on Rate Base	6.781%		7.261%		7.479%
64						
65	Return on Equity	8.499%		9.393%		9.800%
66						
67	TAX CALCULATION:					
68	Operating Revenue	515,002,417	49,266,806	564,269,224	22,426,797	586,696,021
69	Other Deductions					
70	Interest (AFUDC)	(20,261,623)	-	(20,261,623)	-	(20,261,623)
71	Interest	168,672,646	-	168,672,646	-	168,672,646
72	Schedule "M" Additions	517,841,906	-	517,841,906	-	517,841,906
73	Schedule "M" Deductions	799,652,955	-	799,652,955	-	799,652,955
74	Income Before Tax	84,780,344	49,266,806	134,047,151	22,426,797	156,473,948
75						
76	State Income Taxes	3,849,028	2,236,713	6,085,741	1,018,177	7,103,917
77	Taxable Income	80,931,317	47,030,093	127,961,410	21,408,620	149,370,031
78						
79	Federal Income Taxes + Other	(63,123,244)	9,876,320	(53,246,924)	4,495,810	(48,751,114)

Ref. Page 2.0

Rocky Mountain Power
UTAH
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 2021

Net Rate Base	$	7,745,613,856	Ref. Page 1.1
Return on Rate Base Requested		7.48%	Ref. Page 2.1
Revenues Required to Earn Requested Return		579,299,340	Ref. Page 1.1
Less Current Operating Revenues		(525,232,756)	Ref. Page 1.1
Increase to Current Revenues		54,066,584	
Net to Gross Bump-up		133.26%	
Price Change Required for Requested Return	$	72,049,907	Ref. Page 1.1
Requested Price Change	$	72,049,907	
Uncollectible Percent		0.195%	Ref. Page 1.3
Increased Uncollectible Expense	$	140,153	
Requested Price Change	$	72,049,907	
Franchise Tax		0.000%	Ref. Page 1.3
Revenue Tax		0.000%	Ref. Page 1.3
Resource Supplier Tax		0.000%	Ref. Page 1.3
PUC Fees Based on General Business Revenues		0.300%	Ref. Page 1.3
Increase Taxes Other Than Income	$	216,150	
Requested Price Change	$	72,049,907	
Uncollectible Expense		(140,153)	Ref. Page 1.1
Taxes Other Than Income		(216,150)	
Income Before Taxes	$	71,693,603	
State Effective Tax Rate		4.54%	Ref. Page 2.0
State Income Taxes	$	3,254,890	
Taxable Income	$	68,438,714	
Federal Income Tax Rate		21.00%	Ref. Page 2.0
Federal Income Taxes	$	14,372,130	
Operating Income		100.000%	
Net Operating Income		75.040%	Ref. Page 1.3
Net to Gross Bump-Up		133.26%	

Rocky Mountain Power
UTAH
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 2021

Operating Revenue	100.000%	
Operating Deductions		
Uncollectible Accounts	0.195%	See Note (1) Below
Taxes Other - Franchise Tax	0.000%	
Taxes Other - Revenue Tax	0.000%	
Taxes Other - Resource Supplier	0.000%	
PUC Fees Based on General Business Revenues	0.300%	
Sub-Total	99.505%	
State Income Tax @ 4.54%	4.518%	
Sub-Total	94.988%	
Federal Income Tax @ 21.00%	19.947%	
Net Operating Income	75.040%	

(1) Uncollectible Accounts =	3,893,752	Pg 2.11, UTAH Situs from Account 904
	2,001,695,945	Pg. 2.2, General Business Revenues

Rocky Mountain Power
Utah General Rate Case - December 2021
Adjustment Summary
REDACTED

	UTAH ALLOCATED UNADJUSTED RESULTS DECEMBER 2019	Tab 3 Revenue Adjustments	Tab 4 O&M Adjustments	Tab 5 Net Power Cost Adjustments	Tab 6 Depreciation & Amortization Adjustments
1 Operating Revenues:					
2 General Business Revenues	1,988,715,510	[redacted]	-	-	[redacted]
3 Interdepartmental	-		-	-	
4 Special Sales	78,282,917		-	19,971,538	
5 Other Operating Revenues	70,101,388		(2,716,081)	-	
6 Total Operating Revenues	2,137,099,816		(2,716,081)	19,971,538	
7					
8 Operating Expenses:					
9 Steam Production	451,142,931	[redacted]	4,095,700	(48,916,477)	[redacted]
10 Nuclear Production	-		-	-	
11 Hydro Production	19,409,835		1,085,315	-	
12 Other Power Supply	462,939,589		3,078,293	(32,724,991)	
13 Transmission	96,044,207		1,718,141	394,121	
14 Distribution	85,455,009		6,529,192	-	
15 Customer Accounting	33,249,315		2,449,447	-	
16 Customer Service & Info	6,511,449		477,757	-	
17 Sales	-		-	-	
18 Administrative & General	50,747,835		4,769,224	-	
19					
20 Total O&M Expenses	1,205,500,169	[redacted]	24,203,069	(81,247,348)	[redacted]
21					
22 Depreciation	305,190,671	[redacted]	-	-	[redacted]
23 Amortization	20,768,321		-	63,742	
24 Taxes Other Than Income	71,685,583		-	-	
25 Income Taxes - Federal	78,802,378		(5,649,060)	20,130,118	
26 Income Taxes - State	20,624,126		(1,279,356)	4,558,914	
27 Income Taxes - Def Net	(11,875,493)		-	176,664	
28 Investment Tax Credit Adj.	(2,284,953)		-	-	
29 Misc Revenue & Expense	(1,588,348)		1,119,232	-	
30					
31 Total Operating Expenses:	1,686,822,455	[redacted]	18,393,885	(56,317,910)	[redacted]
32					
33 Operating Rev For Return:	450,277,361	[redacted]	(21,109,966)	76,289,447	[redacted]
34					
35 Rate Base:					
36 Electric Plant In Service	12,242,571,339	[redacted]	-	1,759,900	[redacted]
37 Plant Held for Future Use	11,265,782		-	-	
38 Misc Deferred Debits	332,552,084		-	-	
39 Elec Plant Acq Adj	17,635,536		-	-	
40 Pensions	1,950,836		-	-	
41 Prepayments	16,466,051		-	-	
42 Fuel Stock	72,830,126		-	-	
43 Material & Supplies	104,244,001		-	-	
44 Working Capital	24,419,769		192,548	(630,413)	
45 Weatherization Loans	2,304		-	-	
46 Misc Rate Base	-		-	-	
47					
48 Total Electric Plant:	12,823,937,828	[redacted]	192,548	1,129,487	[redacted]
49					
50 Rate Base Deductions:					
51 Accum Prov For Deprec	(4,060,488,632)	[redacted]	-	-	[redacted]
52 Accum Prov For Amort	(254,122,375)		-	(34,527)	
53 Accum Def Income Tax	(1,787,640,626)		(162,058)	(197,769)	
54 Unamortized ITC	(115,230)		-	-	
55 Customer Adv For Const	(31,278,618)		-	-	
56 Customer Service Deposits	-		-	-	
57 Misc Rate Base Deductions	(241,470,701)		6,309,806	-	
58					
59 Total Rate Base Deductions	(6,375,116,182)	[redacted]	6,147,748	(232,295)	[redacted]
60					
61 Total Rate Base:	6,448,821,646	[redacted]	6,340,296	897,191	[redacted]
62					
63 Return on Rate Base	6.982%	[redacted]	-0.334%	1.181%	[redacted]
64					
65 Return on Equity	8.857%	[redacted]	-0.623%	2.200%	[redacted]
66					
67 TAX CALCULATION:					
68 Operating Revenue	535,543,420	[redacted]	(28,038,382)	101,155,143	[redacted]
69 Other Deductions					
70 Interest (AFUDC)	(32,072,175)	[redacted]	-	-	[redacted]
71 Interest	140,487,434		141,261	19,989	
72 Schedule "M" Additions	506,676,468		-	63,742	
73 Schedule "M" Deductions	479,528,727		-	782,277	
74 Income Before Tax	454,275,902		(28,179,643)	100,416,619	
75					
76 State Income Taxes	20,624,126	[redacted]	(1,279,356)	4,558,914	[redacted]
77 Taxable Income	433,651,776		(26,900,287)	95,857,704	
78					
79 Federal Income Taxes + Other	78,802,378	[redacted]	(5,649,060)	20,130,118	[redacted]
APPROXIMATE PRICE CHANGE	61,934,348	[redacted]	28,786,069	(101,578,361)	[redacted]

Rocky Mountain Power
Utah General Rate Case - December 2021
Adjustment Summary
REDACTED

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		Tax Adjustments	Rate Base Adjustments	Rebuttal Adjustments	Results of Operations December 2021
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4	Special Sales	-	-	(61,532)	[redacted]
5	Other Operating Revenues	-	-	1,685,955	[redacted]
6	Total Operating Revenues	-	-	1,624,423	[redacted]
7					
8	Operating Expenses:				
9	Steam Production	-	(10,617,592)	2,591,195	[redacted]
10	Nuclear Production	-	-	-	[redacted]
11	Hydro Production	-	-	(144,391)	[redacted]
12	Other Power Supply	-	8,771,738	317,047	[redacted]
13	Transmission	-	-	(2,128,947)	[redacted]
14	Distribution	-	-	503,836	[redacted]
15	Customer Accounting	-	-	(571,359)	[redacted]
16	Customer Service & Info	-	-	(55,943)	[redacted]
17	Sales	-	-	-	[redacted]
18	Administrative & General	-	-	1,327,489	[redacted]
19					
20	Total O&M Expenses	-	(1,845,854)	1,838,928	[redacted]
21					
22	Depreciation	-	50,838,862	(1,099,066)	[redacted]
23	Amortization	-	4,268,426	(2,958,845)	[redacted]
24	Taxes Other Than Income	14,331,400	-	4,203,647	[redacted]
25	Income Taxes - Federal	(86,388,387)	(70,785,634)	6,696,442	[redacted]
26	Income Taxes - State	(3,062,690)	(16,030,987)	381,796	[redacted]
27	Income Taxes - Def Net	(4,677,906)	65,825,921	(1,879,644)	[redacted]
28	Investment Tax Credit Adj.	1,167,659	-	-	[redacted]
29	Misc Revenue & Expense	-	681,136	4	[redacted]
30					
31	Total Operating Expenses:	(78,629,924)	32,951,870	7,183,261	[redacted]
32					
33	Operating Rev For Return:	78,629,924	(32,951,870)	(5,558,838)	[redacted]
34					
35	Rate Base:				
36	Electric Plant In Service	-	1,518,727,672	(60,667,479)	[redacted]
37	Plant Held for Future Use	-	(4,908,218)	-	[redacted]
38	Misc Deferred Debits	-	(73,204,422)	(360,162)	[redacted]
39	Elec Plant Acq Adj	-	(4,810,804)	(1,708,124)	[redacted]
40	Pensions	-	13,273,757	(34,785)	[redacted]
41	Prepayments	-	-	(26,595)	[redacted]
42	Fuel Stock	-	1,514,358	-	[redacted]
43	Material & Supplies	-	(2,932,863)	4,521	[redacted]
44	Working Capital	(837,303)	(1,214,406)	478,785	[redacted]
45	Weatherization Loans	-	(2,305)	0	[redacted]
46	Misc Rate Base	-	-	-	[redacted]
47					
48	Total Electric Plant:	(837,303)	1,446,442,770	(62,313,840)	[redacted]
49					
50	Rate Base Deductions:				
51	Accum Prov For Deprec	-	83,718,740	(570,046)	[redacted]
52	Accum Prov For Amort	-	526,101	396,057	[redacted]
53	Accum Def Income Tax	668,586,992	(59,478,549)	13,072,433	[redacted]
54	Unamortized ITC	30,253	-	-	[redacted]
55	Customer Adv For Const	-	(6,763,542)	-	[redacted]
56	Customer Service Deposits	-	(16,275,584)	-	[redacted]
57	Misc Rate Base Deductions	(574,605,644)	30,323,848	3,658,519	[redacted]
58					
59	Total Rate Base Deductions	94,011,601	32,051,014	16,556,963	[redacted]
60					
61	Total Rate Base:	93,174,298	1,478,493,784	(45,756,877)	[redacted]
62					
63	Return on Rate Base	1.131%	-2.110%	-0.032%	[redacted]
64					
65	Return on Equity	2.107%	-3.931%	-0.059%	[redacted]
66					
67	TAX CALCULATION:				
68	Operating Revenue	(14,331,400)	(53,942,570)	(360,244)	[redacted]
69	Other Deductions				
70	Interest (AFUDC)	11,744,704	-	65,848	[redacted]
71	Interest	2,075,916	32,940,723	(1,004,881)	[redacted]
72	Schedule "M" Additions	(57,404,777)	84,064,242	(5,016,935)	[redacted]
73	Schedule "M" Deductions	(18,096,674)	350,286,385	(12,847,759)	[redacted]
74	Income Before Tax	(67,460,124)	(353,105,435)	8,409,613	[redacted]
75					
76	State Income Taxes	(3,062,690)	(16,030,987)	381,796	[redacted]
77	Taxable Income	(64,397,434)	(337,074,449)	8,027,817	[redacted]
78					
79	Federal Income Taxes + Other	(86,388,387)	(70,785,634)	6,696,442	[redacted]
	APPROXIMATE PRICE CHANGE	(95,224,564)	195,693,205	(23,736,554)	[redacted]

Rocky Mountain Power
RESULTS OF OPERATIONS

USER SPECIFIC INFORMATION

STATE:	UTAH
PERIOD:	TWELVE MONTHS ENDING DECEMBER 2021
FILE:	UT GRC JAM DEC 2021 Test Period
PREPARED BY:	Revenue Requirement Department
DATE:	9/30/2020
TIME:	1:12:18 PM
TYPE OF RATE BASE:	13-Month Average
ALLOCATION METHOD:	**2020 PROTOCOL**
FERC JURISDICTION:	Separate Jurisdiction
8 OR 12 CP:	12 Coincident Peaks
DEMAND %	75% Demand
ENERGY %	25% Energy

TAX INFORMATION

TAX RATE ASSUMPTIONS:	TAX RATE
FEDERAL RATE	21.00%
STATE EFFECTIVE RATE	4.54%
TAX GROSS UP FACTOR	1.326
FEDERAL/STATE COMBINED RATE	24.5866%

CAPITAL STRUCTURE INFORMATION

	CAPITAL STRUCTURE	EMBEDDED COST	WEIGHTED COST
DEBT	46.32%	4.79%	2.22%
PREFERRED	0.01%	6.75%	0.00%
COMMON	53.67%	9.80%	5.26%
	100.00%		7.48%

OTHER INFORMATION

For information and support regarding capital structure and cost of debt, see testimony of Ms. Nikki L. Kobliha.
For information and support regarding return on equity, see testimony of Ms. Ann E. Bulkley.

2020 PROTOCOL
13-Month Average

RESULTS OF OPERATIONS SUMMARY

			DECEMBER 2019 UNADJUSTED RESULTS		DECEMBER 2021 NORMALIZED RESULTS	
	Description of Account Summary:	**Ref**	**TOTAL**	**UTAH**	**TOTAL**	**UTAH**
1	Operating Revenues					
2	General Business Revenues	2.2	4,697,555,109	1,988,715,510	4,710,535,544	2,001,695,945
3	Interdepartmental	2.2	0	0	0	0
4	Special Sales	2.2	192,271,657	78,282,917	237,838,379	112,151,329
5	Other Operating Revenues	2.3	175,882,372	70,080,471	183,857,495	75,210,750
6	Total Operating Revenues	2.3	5,065,709,138	2,137,078,899	5,132,231,418	2,189,058,024
7						
8	Operating Expenses:					
9	Steam Production	2.5	1,040,566,325	451,142,931	916,262,305	397,319,710
10	Nuclear Production	2.5	0	0	0	0
11	Hydro Production	2.6	44,115,770	19,409,835	46,588,311	20,497,691
12	Other Power Supply	2.7, .8	989,873,255	462,939,589	948,308,002	442,281,907
13	Transmission	2.9	218,366,627	96,044,207	219,500,626	95,890,672
14	Distribution	2.10	202,761,779	85,367,097	217,196,916	92,477,865
15	Customer Accounting	2.11	76,859,684	33,249,315	80,189,558	34,769,928
16	Customer Service & Infor	2.12	101,544,683	6,511,449	102,408,876	6,902,035
17	Sales	2.12	0	0	0	0
18	Administrative & General	2.13	123,122,911	50,488,544	137,440,758	55,938,610
19						
20	Total O & M Expenses	2.13	2,797,211,034	1,205,152,965	2,667,895,352	1,146,078,418
21						
22	Depreciation	2.14	731,135,346	305,145,817	996,360,273	433,162,280
23	Amortization	2.15	55,249,227	20,733,797	54,713,635	4,382,255
24	Taxes Other Than Income	2.15	199,137,026	71,208,743	242,020,311	90,220,630
25	Income Taxes - Federal	2.18	180,479,645	71,146,596	(144,158,097)	(63,123,244)
26	Income Taxes - State	2.17	47,186,904	18,890,291	8,592,535	3,849,028
27	Income Taxes - Def Net	2.16	(36,203,211)	(7,623,563)	103,244,855	50,161,171
28	Investment Tax Credit Adj.	2.15	(2,738,724)	(2,284,953)	(1,339,178)	(1,117,294)
29	Misc Revenue & Expense	2.3	(3,395,390)	(1,584,840)	410,159	212,024
30						
31	Total Operating Expenses	2.18	3,968,061,858	1,680,784,854	3,927,739,844	1,663,825,268
32						
33	Operating Revenue for Return		1,097,647,280	456,294,045	1,204,491,574	525,232,756
34						
35	Rate Base:					
36	Electric Plant in Service	2.26	28,204,842,852	12,240,487,353	31,431,332,484	13,702,391,432
37	Plant Held for Future Use	2.26	26,174,621	11,265,782	15,018,946	6,357,564
38	Misc Deferred Debits	2.28	867,962,720	331,155,679	698,917,519	258,987,500
39	Elec Plant Acq Adj	2.26,.27	26,756,854	17,635,536	12,708,143	11,116,608
40	Pensions	2.27	4,464,716	1,937,621	34,843,256	15,189,809
41	Prepayments	2.28	49,459,714	16,387,199	49,459,714	16,439,455
42	Fuel Stock	2.27	167,980,844	72,830,126	171,473,671	74,344,484
43	Material & Supplies	2.28	246,195,997	104,248,439	239,530,021	101,315,658
44	Working Capital	2.28	44,217,537	24,210,969	20,238,091	13,410,124
45	Weatherization Loans	2.27	(11,565,455)	2,319	(11,564,941)	(1)
46	Miscellaneous Rate Base	2.29	0	0	0	0
47						
48	Total Electric Plant		29,626,490,400	12,820,161,022	32,661,956,904	14,199,552,634
49						
50	Rate Base Deductions:					
51	Accum Prov For Depr	2.32	(9,906,332,026)	(4,060,171,405)	(9,892,571,849)	(4,183,178,675)
52	Accum Prov For Amort	2.33	(618,645,394)	(253,248,584)	(629,418,377)	(276,093,963)
53	Accum Def Income Taxes	2.30	(4,083,287,763)	(1,787,562,057)	(2,838,144,486)	(1,164,479,247)
54	Unamortized ITC	2.30	(297,463)	(115,230)	(221,328)	(84,977)
55	Customer Adv for Const	2.29	(74,342,021)	(31,278,618)	(74,342,021)	(38,042,160)
56	Customer Service Deposits	2.29	0	0	(16,275,584)	(16,275,584)
57	Misc. Rate Base Deductions	2.29	(889,649,950)	(240,962,826)	(1,376,857,053)	(775,784,172)
58						
59	Total Rate Base Deductions		(15,572,554,618)	(6,373,338,720)	(14,827,830,699)	(6,453,938,778)
60						
61	Total Rate Base		14,053,935,782	6,446,822,303	17,834,126,206	7,745,613,856
62						
63	Return on Rate Base					6.781%
64						
65	Return on Equity					8.499%
66	Net Power Costs				1,432,095,986	624,146,199
67	100 Basis Points in Equity:					
68	Revenue Requirement Impact				126,921,416	55,123,771
69	Rate Base Decrease				(1,312,872,818)	(568,081,678)

2020 PROTOCOL
13-Month Average

	FERC ACCT	**DESCRIP**	**BUS FUNC**	**FACTOR**	**Ref**	**DECEMBER 2019 UNADJUSTED RESULTS TOTAL**	**DECEMBER 2019 UNADJUSTED RESULTS UTAH**	**DECEMBER 2021 NORMALIZED RESULTS TOTAL**	**DECEMBER 2021 NORMALIZED RESULTS UTAH**
70	Sales to Ultimate Customers								
71	440	Residential Sales							
72			0	S		1,815,760,353	762,483,089	1,807,769,884	754,492,620
73									
74					B1	1,815,760,353	762,483,089	1,807,769,884	754,492,620
75									
76	442	Commercial & Industrial Sales							
77			0	S		2,863,596,713	1,218,669,565	2,885,523,279	1,240,596,131
78			P	SE		-	-	-	-
79			PT	SG		-	-	-	-
80									
81									
82					B1	2,863,596,713	1,218,669,565	2,885,523,279	1,240,596,131
83									
84	444	Public Street & Highway Lighting							
85			0	S		18,198,044	7,562,856	17,242,381	6,607,194
86			0	SO		-	-	-	-
87					B1	18,198,044	7,562,856	17,242,381	6,607,194
88									
89	445	Other Sales to Public Authority							
90			0	S		-	-	-	-
91									
92					B1	-	-	-	-
93									
94	448	Interdepartmental							
95			DPW	S		-	-	-	-
96			GP	SO		-	-	-	-
97					B1	-	-	-	-
98									
99	**Total Sales to Ultimate Customers**				**B1**	**4,697,555,109**	**1,988,715,510**	**4,710,535,544**	**2,001,695,945**
100									
101									
102									
103	447	Sales for Resale-Non NPC							
104			P	S		14,230,443	(77,250)	14,659,954	13,958,405
105					B1	14,230,443	(77,250)	14,659,954	13,958,405
106									
107	447NPC	Sales for Resale-NPC							
108			P	SG		182,171,613	80,150,952	223,178,425	98,192,924
109			P	SE		(4,130,399)	(1,790,784)	-	-
110			P	SG		-	-	-	-
111					B1	178,041,214	78,360,168	223,178,425	98,192,924
112									
113		Total Sales for Resale			B1	192,271,657	78,282,917	237,838,379	112,151,329
114									
115	449	Provision for Rate Refund							
116			P	S		-	-	-	-
117			P	SG		-	-	-	-
118									
119									
120					B1	-	-	-	-
121									
122	**Total Sales from Electricity**				**B1**	**4,889,826,766**	**2,066,998,428**	**4,948,373,923**	**2,113,847,274**
123	450	Forfeited Discounts & Interest							
124			CUST	S		9,415,630	3,311,424	9,415,630	3,311,424
125			CUST	SO		-	-	-	-
126					B1	9,415,630	3,311,424	9,415,630	3,311,424
127									
128	451	Misc Electric Revenue							
129			CUST	S		8,817,083	4,310,261	6,847,075	2,340,253
130			GP	SG		-	-	-	-
131			GP	SO		28,720	12,464	28,720	12,520
132					B1	8,845,803	4,322,725	6,875,795	2,352,773
133									
134	453	Water Sales							
135			P	SG		53,658	23,608	53,658	23,608
136					B1	53,658	23,608	53,658	23,608
137									
138	454	Rent of Electric Property							
139			DPW	S		9,431,667	3,537,422	9,868,917	3,974,672
140			T	SG		5,409,673	2,380,121	5,409,673	2,380,121
141			T	SG		-	-	-	-
142			GP	SO		2,618,388	1,136,342	2,618,388	1,141,478
143					B1	17,459,728	7,053,885	17,896,978	7,496,271

2020 PROTOCOL
13-Month Average

	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2019 UNADJUSTED RESULTS TOTAL	DECEMBER 2019 UNADJUSTED RESULTS UTAH	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS UTAH
144									
145									
146									
147	456	Other Electric Revenue							
148			DMSC	S		3,243,618	(4,728,044)	4,365,469	(1,768,513)
149			CUST	CN		-	-	-	-
150			OTHSE	SE		14,558,486	6,312,008	14,558,486	6,312,008
151			OTHSO	SO		4,419,730	1,918,098	4,419,730	1,926,768
152			OTHSGR	SG		117,885,718	51,866,766	126,271,748	55,556,410
153									
154									
155					B1	140,107,552	55,368,829	149,615,433	62,026,673
156									
157	**Total Other Electric Revenues**				**B1**	**175,882,372**	**70,080,471**	**183,857,495**	**75,210,750**
158									
159	**Total Electric Operating Revenues**				**B1**	**5,065,709,138**	**2,137,078,899**	**5,132,231,418**	**2,189,058,024**
160									
161	Summary of Revenues by Factor								
162		S				4,742,693,551	1,995,069,324	4,755,692,590	2,023,512,188
163		CN				-	-	-	-
164		SE				10,428,087	4,521,223	14,558,486	6,312,008
165		SO				7,066,838	3,066,904	7,066,838	3,080,766
166		SG				305,520,662	134,421,448	354,913,505	156,153,063
167		DGP				-	-	-	-
168									
169	Total Electric Operating Revenues					5,065,709,138	2,137,078,899	5,132,231,418	2,189,058,024
170	Miscellaneous Revenues								
171	41160	Gain on Sale of Utility Plant - CR							
172			DPW	S		-	-	-	-
173			T	SG		-	-	-	-
174			G	SO		-	-	-	-
175			T	SG		-	-	-	-
176			P	SG		-	-	-	-
177					B6	-	-	-	-
178									
179	41170	Loss on Sale of Utility Plant							
180			DPW	S		-	-	-	-
181			T	SG		-	-	-	-
182					B6	-	-	-	-
183									
184	4118	Gain from Emission Allowances							
185			P	S		-	-	-	-
186			P	SE		(173)	(75)	(173)	(75)
187					B6	(173)	(75)	(173)	(75)
188									
189	41181	Gain from Disposition of NOX Credits							
190			P	SE		-	-	-	-
191					B6	-	-	-	-
192									
193	4194	Impact Housing Interest Income							
194			P	SG		-	-	-	-
195					B6	-	-	-	-
196									
197	421	(Gain) / Loss on Sale of Utility Plant							
198			DPW	S		222,859	-	795,078	(91)
199			T	SG		-	-	-	-
200			T	SG		-	-	-	-
201			P	CN		-	-	-	-
202			PTD	SO		(1,185,025)	(514,283)	(3,839)	(1,673)
203			P	SG		(2,433,051)	(1,070,481)	(1,062,043)	(467,272)
204					B6	(3,395,217)	(1,584,765)	(270,803)	(469,037)
205									
206	**Total Miscellaneous Revenues**				**B6**	**(3,395,390)**	**(1,584,840)**	**(270,977)**	**(469,112)**
207	Miscellaneous Expenses								
208	4311	Interest on Customer Deposits							
209			CUST	S		-	-	681,136	681,136
210						-	-	681,136	681,136
211	**Total Miscellaneous Expenses**				B6	**-**	**-**	**681,136**	**681,136**
212									
213	**Net Misc Revenue and Expense**				**B6**	**(3,395,390)**	**(1,584,840)**	**410,159**	**212,024**
214									

2020 PROTOCOL
13-Month Average

	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2019 UNADJUSTED RESULTS TOTAL	UTAH	DECEMBER 2021 NORMALIZED RESULTS TOTAL	UTAH
215	500	Operation Supervision & Engineering							
216			P	SG		15,517,985	6,827,525	16,967,058	7,465,081
217			P	SG		2,307,136	1,015,082	2,307,136	1,015,082
218			P	SG		-	-	-	-
219					B2	17,825,121	7,842,607	19,274,194	8,480,163
220									
221	501	Fuel Related-Non NPC							
222			P	S		4,028,247	-	4,028,247	-
223			P	SE		15,215,943	6,597,056	15,371,091	6,664,322
224			P	SE		-	-	-	-
225			P	SE		-	-	-	-
226			P	SE		2,888,332	1,252,271	2,888,332	1,252,271
227					B2	22,132,521	7,849,327	22,287,669	7,916,594
228									
229	501NPC	Fuel Related-NPC							
230			P	S		439,817	-	-	-
231			P	SE		673,602,868	292,048,670	568,686,663	246,560,981
232			P	SE		-	-	-	-
233			P	SE		-	-	-	-
234			P	SE		38,598,189	16,734,712	38,598,189	16,734,712
235					B2	712,640,874	308,783,382	607,284,852	263,295,693
236									
237		Total Fuel Related			B2	734,773,395	316,632,710	629,572,521	271,212,286
238									
239	502	Steam Expenses							
240			P	SG		74,134,628	32,617,382	75,878,400	33,384,598
241			P	SG		6,114,697	2,690,314	6,114,697	2,690,314
242			P	SG		-	-	-	-
243					B2	80,249,325	35,307,695	81,993,097	36,074,911
244									
245	503	Steam From Other Sources-Non-NPC							
246			P	SE		-	-	10,296	4,464
247					B2	-	-	10,296	4,464
248									
249	503NPC	Steam From Other Sources-NPC							
250			P	SE		4,836,772	2,097,041	4,497,520	1,949,954
251					B2	4,836,772	2,097,041	4,497,520	1,949,954
252									
253	505	Electric Expenses							
254			P	SG		1,223,111	538,138	1,223,191	538,173
255			P	SG		309,411	136,133	309,411	136,133
256			P	SG		-	-	-	-
257					B2	1,532,522	674,271	1,532,601	674,306
258									
259	506	Misc. Steam Expense							
260			P	S		-	-	-	-
261			P	SG		24,989,869	10,994,917	27,861,054	12,258,167
262			P	SG		-	-	(23,692,497)	(10,424,106)
263			P	SG		2,052,900	903,224	2,052,900	903,224
264					B2	27,042,769	11,898,142	6,221,456	2,737,285
265									
266	507	Rents							
267			P	SG		492,466	216,673	492,466	216,673
268			P	SG		-	-	-	-
269					B2	492,466	216,673	492,466	216,673
270									
271	510	Maint Supervision & Engineering							
272			P	SG		4,933,805	2,170,751	5,234,744	2,303,156
273			P	SG		-	-	-	-
274			P	SG		2,359,677	1,038,199	(3,680,990)	(1,619,544)
275					B2	7,293,482	3,208,949	1,553,754	683,613
276									
277									
278									
279	511	Maintenance of Structures							
280			P	SG		23,528,487	10,351,946	24,257,456	10,672,674
281			P	SG		4,086,250	1,797,848	4,086,250	1,797,848
282			P	SG		-	-	-	-
283					B2	27,614,737	12,149,794	28,343,706	12,470,522
284									
285	512	Maintenance of Boiler Plant							
286			P	SG		84,184,977	37,039,284	86,740,522	38,163,659
287			P	SG		4,854,765	2,135,975	4,854,765	2,135,975
288			P	SG		-	-	-	-
289					B2	89,039,742	39,175,259	91,595,287	40,299,634
290									
291	513	Maintenance of Electric Plant							
292			P	SG		38,453,187	16,918,440	39,538,871	17,396,114
293			P	SG		1,055,833	464,540	1,055,833	464,540
294			P	SG		-	-	-	-
295					B2	39,509,020	17,382,980	40,594,704	17,860,654

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2019 UNADJUSTED RESULTS TOTAL	UTAH	DECEMBER 2021 NORMALIZED RESULTS TOTAL	UTAH
296									
297	514	Maintenance of Misc. Steam Plant							
298			P	SG		9,079,454	3,994,733	9,303,182	4,093,167
299			P	SG		1,277,520	562,077	1,277,520	562,077
300			P	SG		-	-	-	-
301					B2	10,356,974	4,556,810	10,580,702	4,655,244
302									
303	**Total Steam Power Generation**				**B2**	**1,040,566,325**	**451,142,931**	**916,262,305**	**397,319,710**
304	517	Operation Super & Engineering							
305			P	SG		-	-	-	-
306					B2	-	-	-	-
307									
308	518	Nuclear Fuel Expense							
309			P	SE		-	-	-	-
310									
311					B2	-	-	-	-
312									
313	519	Coolants and Water							
314			P	SG		-	-	-	-
315					B2	-	-	-	-
316									
317	520	Steam Expenses							
318			P	SG		-	-	-	-
319					B2	-	-	-	-
320									
321									
322									
323	523	Electric Expenses							
324			P	SG		-	-	-	-
325					B2	-	-	-	-
326									
327	524	Misc. Nuclear Expenses							
328			P	SG		-	-	-	-
329					B2	-	-	-	-
330									
331	528	Maintenance Super & Engineering							
332			P	SG		-	-	-	-
333					B2	-	-	-	-
334									
335	529	Maintenance of Structures							
336			P	SG		-	-	-	-
337					B2	-	-	-	-
338									
339	530	Maintenance of Reactor Plant							
340			P	SG		-	-	-	-
341					B2	-	-	-	-
342									
343	531	Maintenance of Electric Plant							
344			P	SG		-	-	-	-
345					B2	-	-	-	-
346									
347	532	Maintenance of Misc Nuclear							
348			P	SG		-	-	-	-
349					B2	-	-	-	-
350									
351	**Total Nuclear Power Generation**				**B2**	**-**	**-**	**-**	**-**
352									
353	535	Operation Super & Engineering							
354			P	SG		-	-	-	-
355			P	SG		-	-	-	-
356			P	SG		8,085,350	3,557,352	8,741,022	3,845,831
357			P	SG		1,377,416	606,029	1,770,192	778,840
358									
359					B2	9,462,766	4,163,380	10,511,215	4,624,671
360									
361	536	Water For Power							
362			P	DGP		-	-	-	-
363			P	SG		36,194	15,925	38,648	17,004
364			P	SG		-	-	-	-
365									
366					B2	36,194	15,925	38,648	17,004
367									
368	537	Hydraulic Expenses							
369			P	SG		-	-	-	-
370			P	SG		3,760,057	1,654,331	3,808,957	1,675,846
371			P	SG		313,252	137,823	315,681	138,892
372									
373					B2	4,073,308	1,792,154	4,124,638	1,814,737

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FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2019 UNADJUSTED RESULTS TOTAL	DECEMBER 2019 UNADJUSTED RESULTS UTAH	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS UTAH
538	Electric Expenses							
		P	DGP		-	-	-	-
		P	SG		-	-	-	-
		P	SG		-	-	-	-
				B2	-	-	-	-
539	Misc. Hydro Expenses							
		P	SG		-	-	-	-
		P	SG		11,932,301	5,249,914	12,536,902	5,515,923
		P	SG		8,106,211	3,566,530	8,590,133	3,779,444
				B2	20,038,512	8,816,444	21,127,035	9,295,367
540	Rents (Hydro Generation)							
		P	DGP		-	-	-	-
		P	SG		1,638,633	720,957	1,638,651	720,966
		P	SG		57,739	25,404	57,739	25,404
				B2	1,696,372	746,361	1,696,390	746,369
541	Maint Supervision & Engineering							
		P	DGP		-	-	-	-
		P	SG		381	168	381	168
		P	SG		-	-	-	-
				B2	381	168	381	168
542	Maintenance of Structures							
		P	SG		-	-	-	-
		P	SG		625,785	275,330	647,640	284,945
		P	SG		20,932	9,209	21,912	9,641
				B2	646,717	284,539	669,551	294,586
543	Maintenance of Dams & Waterways							
		P	SG		-	-	-	-
		P	SG		1,095,817	482,132	1,131,095	497,654
		P	SG		674,493	296,760	702,804	309,216
				B2	1,770,311	778,892	1,833,899	806,870
544	Maintenance of Electric Plant							
		P	SG		-	-	-	-
		P	SG		1,619,288	712,446	1,701,732	748,720
		P	SG		393,834	173,277	412,909	181,670
				B2	2,013,122	885,723	2,114,641	930,389
545	Maintenance of Misc. Hydro Plant							
		P	SG		-	-	-	-
		P	SG		-	-	-	-
		P	SG		3,698,810	1,627,384	3,782,139	1,664,046
		P	SG		679,277	298,865	689,774	303,484
				B2	4,378,087	1,926,249	4,471,913	1,967,530
Total Hydraulic Power Generation				**B2**	**44,115,770**	**19,409,835**	**46,588,311**	**20,497,691**
546	Operation Super & Engineering							
		P	SG		355,808	156,546	356,184	156,712
		P	SG		-	-	-	-
		P	SG		-	-	-	-
				B2	355,808	156,546	356,184	156,712
547	Fuel-Non-NPC							
		P	SE		-	-	-	-
		P	SE		-	-	-	-
				B2	-	-	-	-
547NPC	Fuel-NPC							
		P	SE		279,047,502	120,984,419	293,319,181	127,172,079
		P	SE		1,160,580	503,184	1,160,580	503,184
				B2	280,208,082	121,487,603	294,479,761	127,675,262

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	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2019 UNADJUSTED RESULTS TOTAL	DECEMBER 2019 UNADJUSTED RESULTS UTAH	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS UTAH
454	548	Generation Expense							
455			P	SG		16,519,013	7,267,953	17,050,467	7,501,779
456			P	SG		734,954	323,362	777,575	342,113
457			P	SG		-	-	-	-
458					B2	17,253,968	7,591,314	17,828,041	7,843,892
460	549	Miscellaneous Other							
461			P	S		103,230	-	106,650	-
462			P	SG		4,415,188	1,942,572	4,764,021	2,096,050
463			P	SG		3,297,027	1,450,609	3,328,026	1,464,248
464			P	SG		-	-	19,937,139	8,771,842
465			P	SG		-	-	-	-
466					B2	7,815,446	3,393,182	28,135,836	12,332,140
471	550	Rents							
472			P	S		383,836	-	383,836	-
473			P	SG		35,823	15,761	35,823	15,761
474			P	SG		2,814,392	1,238,262	2,814,392	1,238,262
475					B2	3,234,050	1,254,023	3,234,050	1,254,023
477	551	Maint Supervision & Engineering							
478			P	SG		-	-	-	-
479					B2	-	-	-	-
481	552	Maintenance of Structures							
482			P	SG		2,316,335	1,019,129	2,389,971	1,051,527
483			P	SG		58,078	25,553	61,639	27,119
484			P	SG		-	-	-	-
485					B2	2,374,413	1,044,682	2,451,610	1,078,647
487	553	Maint of Generation & Electric Plant							
488			P	SG		4,248,958	1,869,435	4,389,910	1,931,451
489			P	SG		7,682,902	3,380,285	7,688,955	3,382,948
490			P	SG		-	-	-	-
491			P	SG		307,244	135,180	836,180	367,898
492					B2	12,239,103	5,384,899	12,915,045	5,682,297
494	554	Maintenance of Misc. Other							
495			P	SG		1,887,493	830,450	1,889,928	831,521
496			P	SG		986,457	434,016	986,686	434,117
497			P	SG		123,631	54,394	128,828	56,681
498			P	SG		-	-	-	-
499					B2	2,997,580	1,318,860	3,005,441	1,322,319
501	**Total Other Power Generation**				**B2**	**326,478,450**	**141,631,110**	**362,405,968**	**157,345,292**
504	555	Purchased Power-Non NPC							
505			DMSC	S		(51,540,008)	-	(51,540,008)	-
506						(51,540,008)	-	(51,540,008)	-
508	555NPC	Purchased Power-NPC							
509			P	S		4,879,895	4,879,895	1,570,674	1,570,674
510			P	SE		(15,254,142)	(6,613,618)	50,516,280	21,901,944
511		Seasonal Co	P	SG		695,109,638	305,830,850	550,174,501	242,063,016
512			P	DGP		-	-	-	-
513						684,735,392	304,097,128	602,261,455	265,535,634
515		Total Purchased Power			B2	633,195,384	304,097,128	550,721,447	265,535,634
517	556	System Control & Load Dispatch							
518			P	SG		770,619	339,053	811,457	357,021
520					B2	770,619	339,053	811,457	357,021
524	557	Other Expenses							
525			P	S		6,324,352	35,000	6,328,567	34,896
526			P	SG		38,258,906	16,832,962	43,195,019	19,004,727
527			P	SGCT		-	-	-	-
528			P	SE		10,002	4,337	10,002	4,337
529			P	SG		-	-	-	-
530			P	TROJP		-	-	-	-
532					B2	44,593,260	16,872,298	49,533,588	19,043,960

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	FERC ACCT	**DESCRIP**	**BUS FUNC**	**FACTOR**	**Ref**	**DECEMBER 2019 UNADJUSTED RESULTS TOTAL**	**UTAH**	**DECEMBER 2021 NORMALIZED RESULTS TOTAL**	**UTAH**
533									
534	Embedded Cost Differentials								
535	Company Owned Hyd		P	DGP		-	-	-	-
536	Company Owned Hyd		P	SG		-	-	-	-
537	Mid-C Contract		P	MC		-	-	-	-
538	Mid-C Contract		P	SG		-	-	-	-
539	Existing QF Contracts		P	S		-	-	-	-
540	Existing QF Contracts		P	SG		-	-	-	-
541									
542						-	-	-	-
543									
544									
545									
546									
547	2020 Protocol Adjustment								
548	Baseline ECD		P	S		(10,164,458)	-	(10,164,458)	-
549	WY QF Adjustment		P	S		(5,000,000)	-	(5,000,000)	-
550	2020 Protocol Adjustment					(15,164,458)	-	(15,164,458)	-
551									
552	**Total Other Power Supply**				**B2**	**663,394,806**	**321,308,479**	**585,902,034**	**284,936,615**
553									
554	**Total Production Expense**				**B2**	**2,074,555,350**	**933,492,355**	**1,911,158,618**	**860,099,308**
555									
556									
557	Summary of Production Expense by Factor								
558		S				(50,545,088)	4,914,896	(54,286,491)	1,605,570
559		SG				1,124,994,392	494,969,387	990,386,976	435,745,491
560		SE				1,000,106,046	433,608,072	975,058,133	422,748,247
561		SNPPH				-	-	-	-
562		TROJP				-	-	-	-
563		SGCT				-	-	-	-
564		DGP				-	-	-	-
565		DEU				-	-	-	-
566		DEP				-	-	-	-
567		SNPPS				-	-	-	-
568		SNPPO				-	-	-	-
569		DGU				-	-	-	-
570		MC				-	-	-	-
571		SSGCT				-	-	-	-
572		SSECT				-	-	-	-
573		SSGC				-	-	-	-
574		SSGCH				-	-	-	-
575		SSECH				-	-	-	-
576	Total Production Expense by Factor					2,074,555,350	933,492,355	1,911,158,618	860,099,308
577	560	Operation Supervision & Engineering							
578			T	SG		7,360,740	3,238,541	8,050,686	3,542,101
579			T	SG		-	-	(3,031,136)	(1,333,624)
580									
581					B2	7,360,740	3,238,541	5,019,550	2,208,476
582									
583	561	Load Dispatching							
584			T	SG		20,414,688	8,981,952	21,323,819	9,381,947
585									
586					B2	20,414,688	8,981,952	21,323,819	9,381,947
587	562	Station Expense							
588			T	SG		3,124,100	1,374,526	3,298,274	1,451,158
589									
590					B2	3,124,100	1,374,526	3,298,274	1,451,158
591									
592	563	Overhead Line Expense							
593			T	SG		1,089,585	479,390	1,135,562	499,619
594									
595					B2	1,089,585	479,390	1,135,562	499,619
596									
597	564	Underground Line Expense							
598			T	SG		-	-	-	-
599									
600					B2	-	-	-	-
601									
602	565	Transmission of Electricity by Others							
603			T	SG		-	-	-	-
604			T	SE		-	-	-	-
605						-	-	-	-
606									
607	565NPC	Transmission of Electricity by Others-NPC							
608			T	SG		140,890,496	61,988,293	40,073,217	17,631,213
609			T	SE		4,934,772	2,139,530	106,677,607	46,251,367
610						145,825,268	64,127,823	146,750,824	63,882,580
611									
612		Total Transmission of Electricity by Others			B2	145,825,268	64,127,823	146,750,824	63,882,580

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566	Misc. Transmission Expense							
		T	SG		3,006,329	1,322,710	3,010,551	1,324,567
				B2	3,006,329	1,322,710	3,010,551	1,324,567
567	Rents - Transmission							
		T	SG		2,244,063	987,332	2,259,046	993,924
				B2	2,244,063	987,332	2,259,046	993,924
568	Maint Supervision & Engineering							
		T	SG		1,304,375	573,892	1,399,884	615,914
				B2	1,304,375	573,892	1,399,884	615,914
569	Maintenance of Structures							
		T	SG		5,788,188	2,546,658	6,069,277	2,670,330
				B2	5,788,188	2,546,658	6,069,277	2,670,330
570	Maintenance of Station Equipment							
		T	SG		11,796,851	5,190,319	12,434,660	5,470,939
				B2	11,796,851	5,190,319	12,434,660	5,470,939
571	Maintenance of Overhead Lines							
		T	SG		16,201,425	7,128,222	16,585,775	7,297,326
		T	SG		-	-	-	-
				B2	16,201,425	7,128,222	16,585,775	7,297,326
572	Maintenance of Underground Lines							
		T	SG		57,535	25,314	59,925	26,366
				B2	57,535	25,314	59,925	26,366
573	Maint of Misc. Transmission Plant							
		T	SG		153,479	67,527	153,479	67,527
				B2	153,479	67,527	153,479	67,527
Total Transmission Expense				**B2**	**218,366,627**	**96,044,207**	**219,500,626**	**95,890,672**
Summary of Transmission Expense by Factor								
		SE			4,934,772	2,139,530	106,677,607	46,251,367
		SG			213,431,855	93,904,676	112,823,019	49,639,306
		SNPT			-	-	-	-
Total Transmission Expense by Factor					218,366,627	96,044,207	219,500,626	95,890,672
580	Operation Supervision & Engineering							
		DPW	S		1,272,172	411,440	2,778,960	1,824,973
		DPW	SNPD		8,248,334	3,978,267	9,026,369	4,352,355
				B2	9,520,507	4,389,707	11,805,328	6,177,328
581	Load Dispatching							
		DPW	S		-	-	-	-
		DPW	SNPD		12,160,239	5,865,024	13,260,307	6,393,885
				B2	12,160,239	5,865,024	13,260,307	6,393,885
582	Station Expense							
		DPW	S		4,704,744	2,156,017	4,900,601	2,251,413
		DPW	SNPD		3,204	1,545	3,420	1,649
				B2	4,707,948	2,157,562	4,904,021	2,253,062
583	Overhead Line Expenses							
		DPW	S		9,956,184	6,582,638	10,595,987	6,989,380
		DPW	SNPD		163	79	177	86
				B2	9,956,347	6,582,716	10,596,164	6,989,465
584	Underground Line Expense							
		DPW	S		621	130	621	130
		DPW	SNPD		-	-	-	-
				B2	621	130	621	130
585	Street Lighting & Signal Systems							
		DPW	S		-	-	-	-
		DPW	SNPD		224,138	108,104	242,941	117,142
				B2	224,138	108,104	242,941	117,142

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586	Meter Expenses							
		DPW	S		2,513,774	807,078	2,691,564	865,294
		DPW	SNPD		12,515	6,036	12,515	6,035
				B2	2,526,289	813,114	2,704,079	871,329
587	Customer Installation Expenses							
		DPW	S		15,268,629	5,553,773	16,308,903	5,929,013
		DPW	SNPD		-	-	-	-
				B2	15,268,629	5,553,773	16,308,903	5,929,013
588	Misc. Distribution Expenses							
		DPW	S		(317,677)	(121,812)	(322,226)	(127,860)
		DPW	SNPD		967,054	466,422	1,249,761	602,612
				B2	649,377	344,610	927,535	474,752
589	Rents							
		DPW	S		2,871,522	476,830	2,916,843	502,813
		DPW	SNPD		2,782	1,342	2,782	1,342
				B2	2,874,305	478,172	2,919,626	504,154
590	Maint Supervision & Engineering							
		DPW	S		3,340,839	1,421,691	3,602,639	1,535,890
		DPW	SNPD		3,040,352	1,466,397	3,268,006	1,575,775
				B2	6,381,191	2,888,087	6,870,645	3,111,664
591	Maintenance of Structures							
		DPW	S		2,231,776	1,009,728	2,231,776	1,009,728
		DPW	SNPD		126,767	61,141	126,767	61,125
				B2	2,358,542	1,070,869	2,358,542	1,070,852
592	Maintenance of Station Equipment							
		DPW	S		7,846,621	3,042,333	8,361,363	3,238,067
		DPW	SNPD		1,818,726	877,193	1,962,847	946,450
				B2	9,665,348	3,919,526	10,324,210	4,184,517
593	Maintenance of Overhead Lines							
		DPW	S		86,403,928	29,792,494	92,253,847	32,175,439
		DPW	SNPD		2,245,821	1,083,186	2,378,177	1,146,715
				B2	88,649,749	30,875,680	94,632,024	33,322,154
594	Maintenance of Underground Lines							
		DPW	S		27,316,639	15,935,491	28,481,951	16,566,925
		DPW	SNPD		9,897	4,773	10,510	5,068
				B2	27,326,536	15,940,265	28,492,461	16,571,993
595	Maintenance of Line Transformers							
		DPW	S		-	-	-	-
		DPW	SNPD		1,003,084	483,799	1,079,029	520,289
				B2	1,003,084	483,799	1,079,029	520,289
596	Maint of Street Lighting & Signal Sys.							
		DPW	S		2,503,642	909,979	2,618,225	927,182
		DPW	SNPD		-	-	-	-
				B2	2,503,642	909,979	2,618,225	927,182
597	Maintenance of Meters							
		DPW	S		626,978	239,425	669,349	255,670
		DPW	SNPD		(97,691)	(47,117)	(107,715)	(51,938)
				B2	529,287	192,308	561,635	203,732
598	Maint of Misc. Distribution Plant							
		DPW	S		1,994,419	641,798	2,000,190	641,798
		DPW	SNPD		4,461,583	2,151,873	4,590,429	2,213,423
				B2	6,456,002	2,793,670	6,590,620	2,855,221
Total Distribution Expense				**B2**	**202,761,779**	**85,367,097**	**217,196,916**	**92,477,865**
Summary of Distribution Expense by Factor								
	S				168,534,811	68,859,034	180,090,594	74,585,855
	SNPD				34,226,968	16,508,063	37,106,322	17,892,010
Total Distribution Expense by Factor					202,761,779	85,367,097	217,196,916	92,477,865
901	Supervision							
		CUST	S		470	-	470	-
		CUST	CN		2,281,716	1,090,875	2,437,307	1,165,262
				B2	2,282,185	1,090,875	2,437,776	1,165,262

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769									
770	902	Meter Reading Expense							
771			CUST	S		13,955,934	4,733,733	14,872,924	5,057,847
772			CUST	CN		639,888	305,927	680,650	325,415
773					B2	14,595,821	5,039,660	15,553,574	5,383,262
774									
775	903	Customer Receipts & Collections							
776			CUST	S		5,770,890	2,935,574	6,172,400	3,157,269
777			CUST	CN		40,794,666	19,503,683	43,238,022	20,671,837
778					B2	46,565,556	22,439,257	49,410,422	23,829,106
779									
780	904	Uncollectible Accounts							
781			CUST	S		12,079,917	3,868,502	12,105,167	3,893,752
782			P	SG		-	-	-	-
783			CUST	CN		988,334	472,517	334,749	160,041
784					B2	13,068,251	4,341,019	12,439,916	4,053,793
785									
786	905	Misc. Customer Accounts Expense							
787			CUST	S		329,926	329,926	329,926	329,926
788			CUST	CN		17,945	8,579	17,945	8,579
789					B2	347,870	338,505	347,870	338,505
790									
791	**Total Customer Accounts Expense**				**B2**	**76,859,684**	**33,249,315**	**80,189,558**	**34,769,928**
792									
793	Summary of Customer Accts Exp by Factor								
794		S				32,137,136	11,867,734	33,480,886	12,438,794
795		CN				44,722,548	21,381,580	46,708,672	22,331,134
796		SG				-	-	-	-
797	Total Customer Accounts Expense by Factor					76,859,684	33,249,315	80,189,558	34,769,928
798									
799	907	Supervision							
800			CUST	S		-	-	-	-
801			CUST	CN		6,737	3,221	5,948	2,844
802					B2	6,737	3,221	5,948	2,844
803									
804	908	Customer Assistance							
805			CUST	S		92,521,120	2,655,759	93,066,873	2,885,548
806			CUST	CN		2,701,777	1,291,703	2,906,980	1,389,810
807									
808									
809					B2	95,222,898	3,947,463	95,973,853	4,275,357
810									
811	909	Informational & Instructional Adv							
812			CUST	S		3,446,996	1,189,567	3,445,810	1,197,553
813			CUST	CN		2,863,520	1,369,031	2,978,468	1,423,988
814					B2	6,310,516	2,558,598	6,424,278	2,621,541
815									
816	910	Misc. Customer Service							
817			CUST	S		-	-	-	-
818			CUST	CN		4,533	2,167	4,797	2,293
819									
820					B2	4,533	2,167	4,797	2,293
821									
822	**Total Customer Service Expense**				**B2**	**101,544,683**	**6,511,449**	**102,408,876**	**6,902,035**
823									
824									
825	Summary of Customer Service Exp by Factor								
826		S				95,968,117	3,845,326	96,512,683	4,083,101
827		CN				5,576,566	2,666,123	5,896,193	2,818,934
828									
829	Total Customer Service Expense by Factor				B2	101,544,683	6,511,449	102,408,876	6,902,035
830									
831									
832	911	Supervision							
833			CUST	S		-	-	-	-
834			CUST	CN		-	-	-	-
835					B2	-	-	-	-
836									
837	912	Demonstration & Selling Expense							
838			CUST	S		-	-	-	-
839			CUST	CN		-	-	-	-
840					B2	-	-	-	-
841									
842	913	Advertising Expense							
843			CUST	S		-	-	-	-
844			CUST	CN		-	-	-	-
845					B2	-	-	-	-

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FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2019 UNADJUSTED RESULTS TOTAL	DECEMBER 2019 UNADJUSTED RESULTS UTAH	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS UTAH
916	Misc. Sales Expense							
		CUST	S		-	-	-	-
		CUST	CN		-	-	-	-
				B2	-	-	-	-
Total Sales Expense				**B2**	**-**	**-**	**-**	**-**
Total Sales Expense by Factor								
	S				-	-	-	-
	CN				-	-	-	-
Total Sales Expense by Factor					-	-	-	-
Total Customer Service Exp Including Sales				**B2**	**101,544,683**	**6,511,449**	**102,408,876**	**6,902,035**
920	Administrative & General Salaries							
		PTD	S		15	-	2,471	374
		CUST	CN		-	-	-	-
		PTD	SO		76,578,643	33,234,006	83,590,994	36,441,233
				B2	76,578,659	33,234,006	83,593,465	36,441,607
921	Office Supplies & expenses							
		PTD	S		253,211	123,657	253,211	123,657
		CUST	CN		86,952	41,571	86,952	41,571
		PTD	SO		9,254,192	4,016,183	10,789,422	4,703,615
				B2	9,594,354	4,181,411	11,129,585	4,868,843
922	A&G Expenses Transferred							
		PTD	S		-	-	-	-
		CUST	CN		-	-	-	-
		PTD	SO		(34,578,091)	(15,006,383)	(36,630,315)	(15,968,872)
				B2	(34,578,091)	(15,006,383)	(36,630,315)	(15,968,872)
923	Outside Services							
		PTD	S		1,671,720	1,258,081	1,671,720	1,258,081
		CUST	CN		-	-	-	-
		PTD	SO		20,368,325	8,839,554	20,368,325	8,879,508
				B2	22,040,045	10,097,635	22,040,045	10,137,589
924	Property Insurance							
		PT	S		10,192,677	2,152,236	8,514,052	473,610
		PT	SG		-	-	-	-
		PTD	SO		4,737,084	2,055,825	3,336,712	1,454,629
				B2	14,929,761	4,208,061	11,850,764	1,928,240
925	Injuries & Damages							
		PTD	S		1,845,855	-	1,845,855	-
		PTD	SO		6,250,814	2,712,761	17,126,481	7,466,236
				B2	8,096,669	2,712,761	18,972,335	7,466,236
926	Employee Pensions & Benefits							
		LABOR	S		448,380	-	448,380	-
		CUST	CN		-	-	-	-
		LABOR	SO		101,775,992	44,169,285	101,775,992	44,368,926
				B2	102,224,372	44,169,285	102,224,372	44,368,926
927	Franchise Requirements							
		DMSC	S		-	-	-	-
		DMSC	SO		-	-	-	-
				B2	-	-	-	-
928	Regulatory Commission Expense							
		DMSC	S		14,999,576	6,488,292	15,054,086	6,496,598
		P	SE		-	-	-	-
		DMSC	SO		5,479,721	2,378,118	5,521,793	2,407,208
		FERC	SG		5,126,539	2,255,549	5,126,539	2,255,549
				B2	25,605,836	11,121,959	25,702,418	11,159,355
929	Duplicate Charges							
		LABOR	S		-	-	-	-
		LABOR	SO		(130,646,461)	(56,698,644)	(130,913,634)	(57,071,391)
				B2	(130,646,461)	(56,698,644)	(130,913,634)	(57,071,391)
930	Misc General Expenses							
		PTD	S		55,230	20,000	55,230	20,000
		CUST	CN		-	-	-	-
		P	SG		-	-	-	-
		LABOR	SO		2,243,870	973,807	2,243,870	978,208
				B2	2,299,100	993,807	2,299,100	998,208

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	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2019 UNADJUSTED RESULTS TOTAL	DECEMBER 2019 UNADJUSTED RESULTS UTAH	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS UTAH
925									
926	931	Rents							
927			PTD	S		362,675	9,974	362,675	9,974
928			PTD	SO		2,178,624	945,491	2,178,624	949,764
929					B2	2,541,299	955,465	2,541,299	959,738
930									
931	935	Maintenance of General Plant							
932			G	S		428,431	97,430	429,817	97,430
933			CUST	CN		50,456	24,123	50,456	24,123
934			G	SO		23,958,481	10,397,629	24,151,051	10,528,575
935					B2	24,437,368	10,519,182	24,631,325	10,650,129
936									
937	**Total Administrative & General Expense**				**B2**	**123,122,911**	**50,488,544**	**137,440,758**	**55,938,610**
938									
939	Summary of A&G Expense by Factor								
940		S				30,257,770	10,149,670	28,637,497	8,479,726
941		SE				-	-	-	-
942		SO				87,601,195	38,017,631	103,539,315	45,137,642
943		SG				5,126,539	2,255,549	5,126,539	2,255,549
944		CN				137,408	65,694	137,408	65,694
945	Total A&G Expense by Factor					123,122,911	50,488,544	137,440,758	55,938,610
946									
947	**Total O&M Expense**				**B2**	**2,797,211,034**	**1,205,152,965**	**2,667,895,352**	**1,146,078,418**
948	403SP	Steam Depreciation							
949			P	SG		30,098,077	13,242,401	50,607,867	22,266,195
950			P	SG		29,477,833	12,969,509	37,620,625	16,552,134
951			P	SG		170,783,645	75,140,531	243,083,084	106,950,475
952			P	SG		15,154,392	6,667,553	-	-
953					B3	245,513,947	108,019,994	331,311,576	145,768,805
954									
955	403NP	Nuclear Depreciation							
956			P	SG		-	-	-	-
957					B3	-	-	-	-
958									
959	403HP	Hydro Depreciation							
960			P	SG		(17,573,171)	(7,731,756)	4,059,159	1,785,929
961			P	SG		1,372,186	603,727	1,296,853	570,583
962			P	SG		51,635,992	22,718,545	25,462,864	11,203,023
963			P	SG		6,080,620	2,675,321	7,223,797	3,178,290
964					B3	41,515,627	18,265,837	38,042,673	16,737,824
965									
966	403OP	Other Production Depreciation							
967			P	SG		-	-	-	-
968			P	SG		57,807,314	25,433,772	53,353,659	23,474,275
969			P	SG		3,263,691	1,435,942	4,148,758	1,825,350
970			P	SG		67,194,413	29,563,861	188,173,825	82,791,775
971					B3	128,265,418	56,433,575	245,676,242	108,091,400
972									
973	403TP	Transmission Depreciation							
974			T	SG		8,646,935	3,804,435	8,156,895	3,588,830
975			T	SG		10,802,100	4,752,654	10,352,004	4,554,623
976			T	SG		93,058,624	40,943,466	112,212,732	49,370,795
977					B3	112,507,659	49,500,555	130,721,631	57,514,247
978									
979									
980									
981	403	Distribution Depreciation							
982	360	Land & Land Rights	DPW	S		429,065	184,689	803,502	449,090
983	361	Structures	DPW	S		2,115,833	960,159	2,830,969	1,465,137
984	362	Station Equipment	DPW	S		(3,638,677)	(10,997,659)	2,372,751	(6,752,816)
985	363	Storage Battery Equ	DPW	S		-	-	-	-
986	364	Poles & Towers	DPW	S		44,079,600	14,324,521	51,328,835	19,443,416
987	365	OH Conductors	DPW	S		20,849,815	6,819,390	25,457,852	10,073,259
988	366	UG Conduit	DPW	S		9,604,186	5,331,334	11,893,012	6,947,541
989	367	UG Conductor	DPW	S		22,509,453	14,361,486	27,860,700	18,140,157
990	368	Line Trans	DPW	S		34,758,471	13,031,357	42,989,821	18,843,751
991	369	Services	DPW	S		19,400,498	7,601,132	24,328,782	11,081,136
992	370	Meters	DPW	S		9,134,491	3,626,551	10,524,032	4,607,746
993	371	Inst Cust Prem	DPW	S		496,454	269,410	548,161	305,922
994	372	Leased Property	DPW	S		-	-	-	-
995	373	Street Lighting	DPW	S		2,242,102	1,044,455	2,610,032	1,304,261
996					B3	161,981,289	56,556,825	203,548,449	85,908,600

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403GP	General Depreciation							
		G-SITUS	S		15,001,279	4,830,631	16,808,985	5,871,335
		G-DGP	SG		23,760	10,454	21,260	9,354
		G-DGU	SG		72,996	32,117	75,915	33,401
		P	SE		100,519	43,581	127,089	55,101
		CUST	CN		955,261	456,704	936,665	447,814
		G-SG	SG		9,895,515	4,353,779	10,478,544	4,610,297
		PTD	SO		15,153,707	6,576,486	18,465,178	8,049,837
		G-SG	SG		8,187	3,602	8,888	3,911
		G-SG	SG		140,182	61,677	137,179	60,355
				B3	41,351,407	16,369,031	47,059,702	19,141,404
403GV0	General Vehicles							
		G-SG	SG		-	-	-	-
				B3	-	-	-	-
403MP	Mining Depreciation							
		P	SE		-	-	-	-
				B3	-	-	-	-
403EP	Experimental Plant Depreciation							
		P	SG		-	-	-	-
		P	SG		-	-	-	-
				B3	-	-	-	-
4031	ARO Depreciation							
		P	S		-	-	-	-
				B3	-	-	-	-
Total Depreciation Expense				**B3**	**731,135,346**	**305,145,817**	**996,360,273**	**433,162,280**
Summary	S				176,982,569	61,387,456	220,357,434	91,779,935
	DGP				-	-	-	-
	DGU				-	-	-	-
	SG				537,943,292	236,681,590	756,473,908	332,829,594
	SO				15,153,707	6,576,486	18,465,178	8,049,837
	CN				955,261	456,704	936,665	447,814
	SE				100,519	43,581	127,089	55,101
	SSGCH				-	-	-	-
	SSGCT				-	-	-	-
Total Depreciation Expense By Factor					731,135,346	305,145,817	996,360,273	433,162,280
404GP	Amort of LT Plant - Leasehold Improvements							
		I-SITUS	S		421,920	4,735	421,985	10,812
		I-SG	SG		-	-	-	-
		PTD	SO		284,353	123,405	284,353	123,963
		I-DGU	SG		-	-	-	-
		CUST	CN		-	-	-	-
		I-DGP	SG		-	-	-	-
				B4	706,273	128,140	706,338	134,775
404SP	Amort of LT Plant - Cap Lease Steam							
		P	SG		-	-	-	-
		P	SG		-	-	-	-
				B4	-	-	-	-
404IP	Amort of LT Plant - Intangible Plant							
		I-SITUS	S		999,640	(3,413,243)	8,719,351	4,307,860
		P	SE		-	-	-	-
		I-SG	SG		14,768,916	6,497,953	6,961,881	3,063,053
		PTD	SO		11,379,693	4,938,619	19,632,272	8,558,628
		CUST	CN		10,889,663	5,206,282	11,980,746	5,727,922
		I-SG	SG		10,565,963	4,648,759	2,620,847	1,153,107
		I-SG	SG		315,841	138,962	296,796	130,583
		I-DGP	SG		78,646	34,602	-	-
		I-SG	SG		-	-	-	-
		I-SG	SG		8,927	3,928	-	-
		I-DGU	SG		16,485	7,253	16,150	7,106
				B4	49,023,774	18,063,117	50,228,044	22,948,259
404MP	Amort of LT Plant - Mining Plant							
		P	SE		-	-	-	-
				B4	-	-	-	-
404OP	Amort of LT Plant - Other Plant							
		P	SG		-	-	-	-
				B4	-	-	-	-

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1077	404HP	Amortization of Other Electric Plant							
1078			P	SG		311,696	137,138	311,696	137,138
1079			P	SG		-	-	-	-
1080			P	SG		-	-	-	-
1081					B4	311,696	137,138	311,696	137,138
1082									
1083	**Total Amortization of Limited Term Plant**				**B4**	**50,041,742**	**18,328,395**	**51,246,077**	**23,220,173**
1084									
1085									
1086	405	Amortization of Other Electric Plant							
1087			GP	S		-	-	-	-
1088									
1089					B4	-	-	-	-
1090									
1091	406	Amortization of Plant Acquisition Adj							
1092			P	S		301,635	301,635	301,635	301,635
1093			P	SG		-	-	-	-
1094			P	SG		-	-	-	-
1095			P	SG		4,781,559	2,103,767	75,351	33,153
1096			P	SO		-	-	-	-
1097					B4	5,083,195	2,405,402	376,987	334,788
1098	407	Amort of Prop Losses, Unrec Plant, etc							
1099			DPW	S		124,290	-	(35,669,881)	(36,226,335)
1100			GP	SO		-	-	-	-
1101			P	SG-P		-	-	-	-
1102			P	SE		-	-	-	-
1103			P	SG		-	-	38,760,452	17,053,629
1104			P	TROJP		-	-	-	-
1105					B4	124,290	-	3,090,571	(19,172,706)
1106									
1107	**Total Amortization Expense**				**B4**	**55,249,227**	**20,733,797**	**54,713,635**	**4,382,255**
1108									
1109									
1110									
1111	Summary of Amortization Expense by Factor								
1112		S				1,847,486	(3,106,872)	(26,226,911)	(31,606,027)
1113		SE				-	-	-	-
1114		TROJP				-	-	-	-
1115		DGP				-	-	-	-
1116		DGU				-	-	-	-
1117		SO				11,664,046	5,062,024	19,916,625	8,682,591
1118		SSGCT				-	-	-	-
1119		SSGCH				-	-	-	-
1120		CN				10,889,663	5,206,282	11,980,746	5,727,922
1121		SG				30,848,033	13,572,363	49,043,174	21,577,769
1122	Total Amortization Expense by Factor					55,249,227	20,733,797	54,713,635	4,382,255
1123	408	Taxes Other Than Income							
1124			DMSC	S		35,083,450	-	35,083,450	-
1125			GP	GPS		148,792,508	64,573,762	191,417,121	83,447,697
1126			GP	SO		12,307,544	5,341,293	12,307,544	5,365,435
1127			P	SE		902,710	391,381	902,710	391,381
1128			P	SG		2,050,814	902,307	2,309,486	1,016,116
1129			DMSC	OPRV-ID		-	-	-	-
1130			GP	EXCTAX		-	-	-	-
1131			GP	SG		-	-	-	-
1132									
1133									
1134									
1135	**Total Taxes Other Than Income**				**B5**	**199,137,026**	**71,208,743**	**242,020,311**	**90,220,630**
1136									
1137									
1138	41140	Deferred Investment Tax Credit - Fed							
1139			PTD	DGU		(2,738,724)	(2,284,953)	(1,339,178)	(1,117,294)
1140									
1141					B7	(2,738,724)	(2,284,953)	(1,339,178)	(1,117,294)
1142									
1143	41141	Deferred Investment Tax Credit - Idaho							
1144			PTD	DGU		-	-	-	-
1145									
1146					B7	-	-	-	-
1147									
1148	**Total Deferred ITC**				**B7**	**(2,738,724)**	**(2,284,953)**	**(1,339,178)**	**(1,117,294)**
1149									
1150									
1151	427	Interest on Long-Term Debt							
1152			GP	S		-	-	395,690,752	171,854,103
1153			GP	SNP		369,853,259	165,829,978	-	-
1154					B6	369,853,259	165,829,978	395,690,752	171,854,103

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	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2019 UNADJUSTED RESULTS TOTAL	DECEMBER 2019 UNADJUSTED RESULTS UTAH	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS UTAH
1155									
1156	428	Amortization of Debt Disc & Exp							
1157			GP	SNP		4,475,935	2,006,861	4,475,935	1,978,618
1158					B6	4,475,935	2,006,861	4,475,935	1,978,618
1159									
1160	429	Amortization of Premium on Debt							
1161			GP	SNP		(11,026)	(4,944)	(11,026)	(4,874)
1162					B6	(11,026)	(4,944)	(11,026)	(4,874)
1163									
1164	431	Other Interest Expense							
1165			NUTIL	OTH		-	-	-	-
1166			GP	SO		-	-	-	-
1167			GP	SNP		24,622,419	11,039,879	24,622,419	10,884,510
1168					B6	24,622,419	11,039,879	24,622,419	10,884,510
1169									
1170	432	AFUDC - Borrowed							
1171			GP	SNP		(36,284,269)	(16,268,667)	(36,284,269)	(16,039,711)
1172						(36,284,269)	(16,268,667)	(36,284,269)	(16,039,711)
1173									
1174		Total Elec. Interest Deductions for Tax			B6	362,656,318	162,603,108	388,493,811	168,672,646
1175									
1176		Non-Regulated Portion of Interest							
1177		427	NUTIL	NUTIL		-	-	-	-
1178		428	NUTIL	NUTIL		-	-	-	-
1179		429	NUTIL	NUTIL		-	-	-	-
1180		431	NUTIL	NUTIL		-	-	-	-
1181									
1182		Total Non-Regulated Interest				-	-	-	-
1183									
1184		Total Interest Deductions for Tax			B6	362,656,318	162,603,108	388,493,811	168,672,646
1185									
1186									
1187	419	Interest & Dividends							
1188			GP	S		-	-	-	-
1189			GP	SNP		(72,317,120)	(32,424,607)	(45,834,876)	(20,261,623)
1190		Total Operating Deductions for Tax			B6	(72,317,120)	(32,424,607)	(45,834,876)	(20,261,623)
1191									
1192									
1193	41010	Deferred Income Tax - Federal-DR							
1194			GP	S		9,824,503	(147,191)	(9,226,593)	(1,418,906)
1195			P	TROJD		-	-	-	-
1196			PT	SG		92,718	40,794	92,718	40,794
1197			LABOR	SO		6,994,325	3,035,434	5,139,616	2,240,600
1198			GP	SNP		26,635,962	11,942,685	17,331,350	7,661,443
1199			P	SE		1,338,953	580,519	46,844	20,310
1200			PT	SG		38,372,712	16,883,033	208,425,662	91,702,077
1201			GP	GPS		22,217,020	9,641,860	10,080,561	4,394,589
1202			DITEXP	DITEXP		-	-	-	-
1203			CUST	BADDEBT		-	-	-	-
1204			CUST	CN		-	-	-	-
1205			IBT	IBT		-	-	-	-
1206			DPW	CIAC		-	-	-	-
1207			GP	SCHMDEXP		-	-	-	-
1208			TAXDEPR	TAXDEPR		168,270,646	75,639,012	203,731,435	91,578,923
1209			DPW	SNPD		(251,156)	(121,135)	1	0
1210					B7	273,495,683	117,495,011	435,621,594	196,219,829
1211									
1212									
1213									
1214	41110	Deferred Income Tax - Federal-CR							
1215			GP	S		(27,497,443)	(4,882,048)	(24,230,733)	(11,099,448)
1216			P	SE		(6,292,526)	(2,728,201)	(356,481)	(154,557)
1217			PT	SG		(348,782)	(153,455)	(348,782)	(153,455)
1218			GP	SNP		(16,729,475)	(7,500,944)	(10,284,908)	(4,546,514)
1219			PT	SG		1,734,106	762,963	(37,344,366)	(16,430,587)
1220			GP	GPS		427,029	185,324	-	-
1221			LABOR	SO		(175,169)	(76,021)	(4,215,013)	(1,837,522)
1222			PT	SNPD		(583,210)	(281,289)	-	-
1223			CUST	BADDEBT		(12,823)	(4,260)	(0)	(0)
1224			P	SGCT		-	-	-	-
1225			DITEXP	DITEXP		-	-	-	-
1226			P	TROJD		14,957	6,564	(1)	(0)
1227			IBT	IBT		-	-	-	-
1228			DPW	CIAC		(28,260,436)	(13,630,335)	(15,122,760)	(7,291,926)
1229			GP	SCHMDEXP		(231,975,121)	(96,816,873)	(240,473,695)	(104,544,648)
1230			TAXDEPR	TAXDEPR		-	-	-	-
1231					B7	(309,698,894)	(125,118,574)	(332,376,739)	(146,058,657)
1232									
1233	**Total Deferred Income Taxes**				**B7**	**(36,203,211)**	**(7,623,563)**	**103,244,855**	**50,161,171**

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2019 UNADJUSTED RESULTS TOTAL	 UTAH	DECEMBER 2021 NORMALIZED RESULTS TOTAL	 UTAH
1234	SCHMAF	Additions - Flow Through							
1235			SCHMAF	S		-	-	-	-
1236			SCHMAF	SNP		-	-	-	-
1237			SCHMAF	SO		-	-	-	-
1238			SCHMAF	SE		-	-	-	-
1239			SCHMAF	TROJP		-	-	-	-
1240			SCHMAF	SG		-	-	-	-
1241					B6	-	-	-	-
1242									
1243	SCHMAP	Additions - Permanent							
1244			P	S		-	-	-	-
1245			P	SE		93,520	40,547	45,960	19,926
1246			LABOR	SNP		-	-	-	-
1247			SCHMAP-SO	SO		3,059,827	1,327,920	3,240,659	1,412,755
1248			SCHMAP	SG		-	-	-	-
1249			DPW	SCHMDEXP		147,603	61,603	99,165	43,111
1250					B6	3,300,949	1,430,070	3,385,783	1,475,793
1251									
1252	SCHMAT	Additions - Temporary							
1253			SCHMAT-SITUS	S		10,237,260	(291,300)	(122,195,484)	(33,434,755)
1254			P	SGCT		-	-	-	-
1255			DPW	CIAC		114,942,433	55,438,065	61,508,140	29,658,132
1256			SCHMAT-SNP	SNP		68,043,062	30,508,260	41,831,356	18,491,839
1257			P	TROJD		(60,836)	(26,697)	0	0
1258			P	SG		-	-	-	-
1259			SCHMAT-SE	SE		25,593,317	11,096,292	1,449,899	628,621
1260			P	SG		(7,047,194)	(3,100,589)	155,324,143	68,338,737
1261			SCHMAT-GPS	GPS		(1,736,838)	(753,762)	(0)	(0)
1262			SCHMAT-SO	SO		712,466	309,200	17,143,542	7,473,674
1263			SCHMAT-SNP	SNPD		2,372,063	1,144,074	0	0
1264			CUST	BADDEBT		52,155	17,325	(0)	(0)
1265			P	TAXDEPR		-	-	-	-
1266			BOOKDEPR	SCHMDEXP		943,502,238	393,779,022	978,068,118	425,209,863
1267					B6	1,156,610,125	488,119,889	1,133,129,714	516,366,113
1268									
1269	TOTAL SCHEDULE - M ADDITIONS				B6	1,159,911,074	489,549,959	1,136,515,497	517,841,906
1270									
1271	SCHMDF	Deductions - Flow Through							
1272			SCHMDF	S		-	-	-	-
1273			SCHMDF	DGP		-	-	-	-
1274			SCHMDF	DGU		-	-	-	-
1275					B6	-	-	-	-
1276	SCHMDP	Deductions - Permanent							
1277			SCHMDP	S		-	-	-	-
1278			P	SE		4,099,703	1,777,476	3,962,306	1,717,906
1279			PTD	SNP		107,935	48,394	107,935	47,713
1280			BOOKDEPR	SCHMDEXP		-	-	-	-
1281			P	SG		-	-	-	-
1282			SCHMDP-SO	SO		-	-	-	-
1283					B6	4,207,638	1,825,870	4,070,241	1,765,619
1284									
1285	SCHMDT	Deductions - Temporary							
1286			GP	S		39,958,772	(598,675)	(37,526,920)	(5,771,065)
1287			CUST	BADDEBT		-	-	-	-
1288			SCHMDT-SNP	SNP		108,335,285	48,573,961	70,491,048	31,161,053
1289			CUST	CN		-	-	-	-
1290			SCHMDT	SG		377,111	165,920	377,111	165,920
1291			CUST	DGP		-	-	-	-
1292			P	SE		5,445,869	2,361,122	190,533	82,608
1293			SCHMDT-SG	SG		156,071,656	68,667,624	847,291,064	372,786,870
1294			SCHMDT-GPS	GPS		90,362,310	39,215,915	41,000,228	17,873,922
1295			SCHMDT-SO	SO		28,447,716	12,345,891	20,904,140	9,113,095
1296			TAXDEPR	TAXDEPR		684,399,818	307,643,236	828,627,928	372,474,934
1297			DPW	SNPD		(1,021,517)	(492,690)	1	0
1298					B6	1,112,377,019	477,882,304	1,771,355,132	797,887,336
1299									
1300	TOTAL SCHEDULE - M DEDUCTIONS				B6	1,116,584,657	479,708,174	1,775,425,373	799,652,955
1301									
1302	**TOTAL SCHEDULE - M ADJUSTMENTS**				**B6**	**43,326,417**	**9,841,785**	**(638,909,876)**	**(281,811,050)**
1303									
1304									
1305									
1306	40911	State Income Taxes							
1307			IBT			47,186,904	18,890,291	8,592,535	3,849,028
1308			IBT	IBT		-	-	-	-
1309		PTC	P	SG		-	-	-	-
1310			IBT	IBT		-	-	-	-
1311	**Total State Tax Expense**					**47,186,904**	**18,890,291**	**8,592,535**	**3,849,028**
1312									
1313									

2020 PROTOCOL
13-Month Average

	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2019 UNADJUSTED RESULTS TOTAL	DECEMBER 2019 UNADJUSTED RESULTS UTAH	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS UTAH
1314	Calculation of Taxable Income:								
1315		Operating Revenues				5,065,709,138	2,137,078,899	5,132,231,418	2,189,058,024
1316		Operating Deductions:							
1317		O & M Expenses				2,797,211,034	1,205,152,965	2,667,895,352	1,146,078,418
1318		Depreciation Expense				731,135,346	305,145,817	996,360,273	433,162,280
1319		Amortization Expense				55,249,227	20,733,797	54,713,635	4,382,255
1320		Taxes Other Than Income				199,137,026	71,208,743	242,020,311	90,220,630
1321		Interest & Dividends (AFUDC-Equity)				(72,317,120)	(32,424,607)	(45,834,876)	(20,261,623)
1322		Misc Revenue & Expense				(3,395,390)	(1,584,840)	410,159	212,024
1323		Total Operating Deductions				3,707,020,124	1,568,231,876	3,915,564,854	1,653,793,984
1324		Other Deductions:							
1325		Interest Deductions				362,656,318	162,603,108	388,493,811	168,672,646
1326		Interest on PCRBS				-	-	-	-
1327		Schedule M Adjustments				43,326,417	9,841,785	(638,909,876)	(281,811,050)
1328									
1329		Income Before State Taxes				1,039,359,113	416,085,700	189,262,878	84,780,344
1330									
1331		State Income Taxes				47,186,904	18,890,291	8,592,535	3,849,028
1332									
1333	Total Taxable Income					992,172,209	397,195,409	180,670,343	80,931,317
1334									
1335	Tax Rate					21.0%	21.0%	21.0%	21.0%
1336									
1337	Federal Income Tax - Calculated					208,356,164	83,411,036	37,940,772	16,995,577
1338									
1339	Adjustments to Calculated Tax:								
1340	40910		P	SE		(65,560)	(28,424)	(18,000)	(7,804)
1341	40910	PTC	P	SG		(27,792,500)	(12,228,005)	(182,078,210)	(80,109,857)
1342	40910		P	SO		(18,459)	(8,011)	(2,659)	(1,159)
1343	40910	IRS Settle	LABOR	S		-	-	-	-
1344	**Federal Income Tax Expense**					**180,479,645**	**71,146,596**	**(144,158,097)**	**(63,123,244)**
1345									
1346	**Total Operating Expenses**					**3,968,061,858**	**1,680,784,854**	**3,927,739,844**	**1,663,825,268**
1347	310	Land and Land Rights							
1348			P	SG		2,327,849	1,024,195	2,327,849	1,024,195
1349			P	SG		33,837,468	14,887,640	33,837,468	14,887,640
1350			P	SG		54,188,889	23,841,755	54,188,889	23,841,755
1351			P	S		-	-	-	-
1352			P	SG		2,635,317	1,159,473	2,635,317	1,159,473
1353					B8	92,989,523	40,913,064	92,989,523	40,913,064
1354									
1355	311	Structures and Improvements							
1356			P	SG		227,107,006	99,921,401	227,107,006	99,921,401
1357			P	SG		314,002,985	138,153,457	314,002,985	138,153,457
1358			P	SG		431,529,571	189,862,215	431,529,571	189,862,215
1359			P	SG		65,503,822	28,820,043	65,503,822	28,820,043
1360					B8	1,038,143,383	456,757,116	1,038,143,383	456,757,116
1361									
1362	312	Boiler Plant Equipment							
1363			P	SG		591,792,444	260,373,869	580,936,316	255,597,445
1364			P	SG		470,343,514	206,939,379	456,622,562	200,902,503
1365			P	SG		3,209,916,266	1,412,282,849	2,769,108,969	1,218,338,667
1366			P	SG		341,946,986	150,448,119	340,600,147	149,855,543
1367					B8	4,613,999,209	2,030,044,216	4,147,267,993	1,824,694,158
1368									
1369	314	Turbogenerator Units							
1370			P	SG		109,651,372	48,243,860	109,651,372	48,243,860
1371			P	SG		109,802,624	48,310,408	109,802,624	48,310,408
1372			P	SG		712,634,145	313,541,194	712,634,145	313,541,194
1373			P	SG		69,082,461	30,394,554	69,082,461	30,394,554
1374					B8	1,001,170,601	440,490,017	1,001,170,601	440,490,017
1375									
1376	315	Accessory Electric Equipment							
1377			P	SG		86,087,278	37,876,249	86,087,278	37,876,249
1378			P	SG		133,435,263	58,708,177	133,435,263	58,708,177
1379			P	SG		200,294,220	88,124,446	200,294,220	88,124,446
1380			P	SG		68,703,253	30,227,712	68,703,253	30,227,712
1381					B8	488,520,013	214,936,584	488,520,013	214,936,584
1382									
1383									
1384									
1385	316	Misc Power Plant Equipment							
1386			P	SG		2,592,891	1,140,807	2,592,891	1,140,807
1387			P	SG		4,947,418	2,176,740	4,947,418	2,176,740
1388			P	SG		21,579,754	9,494,552	21,579,754	9,494,552
1389			P	SG		4,139,401	1,821,233	4,139,401	1,821,233
1390					B8	33,259,464	14,633,332	33,259,464	14,633,332

2020 PROTOCOL
13-Month Average

	FERC		BUS			DECEMBER 2019 UNADJUSTED RESULTS		DECEMBER 2021 NORMALIZED RESULTS	
	ACCT	DESCRIP	FUNC	FACTOR	Ref	TOTAL	UTAH	TOTAL	UTAH
1391									
1392	317	Steam Plant ARO							
1393			P	S		-	-	-	-
1394					B8	-	-	-	-
1395									
1396	SP	Unclassified Steam Plant - Account 300							
1397			P	SG		46,348,779	20,392,303	46,348,779	20,392,303
1398					B8	46,348,779	20,392,303	46,348,779	20,392,303
1399									
1400									
1401	**Total Steam Production Plant**				**B8**	**7,314,430,972**	**3,218,166,630**	**6,847,699,757**	**3,012,816,573**
1402									
1403									
1404	Summary of Steam Production Plant by Factor								
1405		S				-	-	-	-
1406		DGP				-	-	-	-
1407		DGU				-	-	-	-
1408		SG				7,314,430,972	3,218,166,630	6,847,699,757	3,012,816,573
1409		SSGCH				-	-	-	-
1410	Total Steam Production Plant by Factor					7,314,430,972	3,218,166,630	6,847,699,757	3,012,816,573
1411	320	Land and Land Rights							
1412			P	SG		-	-	-	-
1413			P	SG		-	-	-	-
1414					B8	-	-	-	-
1415									
1416	321	Structures and Improvements							
1417			P	SG		-	-	-	-
1418			P	SG	B8	-	-	-	-
1419						-	-	-	-
1420									
1421	322	Reactor Plant Equipment							
1422			P	SG		-	-	-	-
1423			P	SG		-	-	-	-
1424					B8	-	-	-	-
1425									
1426	323	Turbogenerator Units							
1427			P	SG		-	-	-	-
1428			P	SG		-	-	-	-
1429					B8	-	-	-	-
1430									
1431	324	Land and Land Rights							
1432			P	SG		-	-	-	-
1433			P	SG		-	-	-	-
1434					B8	-	-	-	-
1435									
1436	325	Misc. Power Plant Equipment							
1437			P	SG		-	-	-	-
1438			P	SG		-	-	-	-
1439					B8	-	-	-	-
1440									
1441									
1442	NP	Unclassified Nuclear Plant - Acct 300							
1443			P	SG		-	-	-	-
1444					B8	-	-	-	-
1445									
1446									
1447	**Total Nuclear Production Plant**				**B8**	**-**	**-**	**-**	**-**
1448									
1449									
1450									
1451	Summary of Nuclear Production Plant by Factor								
1452		DGP				-	-	-	-
1453		DGU				-	-	-	-
1454		SG				-	-	-	-
1455									
1456	Total Nuclear Plant by Factor					-	-	-	-
1457									
1458	330	Land and Land Rights							
1459			P	SG		10,332,372	4,545,985	10,332,372	4,545,985
1460			P	SG		5,268,322	2,317,930	5,268,322	2,317,930
1461			P	SG		19,440,549	8,553,355	19,440,549	8,553,355
1462			P	SG		1,278,861	562,667	1,278,861	562,667
1463					B8	36,320,104	15,979,937	36,320,104	15,979,937
1464									
1465	331	Structures and Improvements							
1466			P	SG		19,737,987	8,684,220	19,737,987	8,684,220
1467			P	SG		4,911,093	2,160,758	4,911,093	2,160,758
1468			P	SG		240,986,535	106,028,046	240,986,535	106,028,046
1469			P	SG		12,019,436	5,288,251	12,019,436	5,288,251
1470					B8	277,655,051	122,161,276	277,655,051	122,161,276

2020 PROTOCOL
13-Month Average

	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2019 UNADJUSTED RESULTS TOTAL	DECEMBER 2019 UNADJUSTED RESULTS UTAH	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS UTAH
1471									
1472	332	Reservoirs, Dams & Waterways							
1473			P	SG		145,556,937	64,041,411	115,528,273	50,829,550
1474			P	SG		18,818,445	8,279,645	18,335,164	8,067,013
1475			P	SG		270,522,732	119,023,234	328,829,169	144,676,607
1476			P	SG		77,163,653	33,950,077	83,830,171	36,883,178
1477					B8	512,061,767	225,294,367	546,522,777	240,456,349
1478									
1479	333	Water Wheel, Turbines, & Generators							
1480			P	SG		28,887,364	12,709,718	28,887,364	12,709,718
1481			P	SG		7,520,182	3,308,692	7,520,182	3,308,692
1482			P	SG		63,524,218	27,949,066	63,524,218	27,949,066
1483			P	SG		39,530,111	17,392,260	39,530,111	17,392,260
1484					B8	139,461,875	61,359,736	139,461,875	61,359,736
1485									
1486	334	Accessory Electric Equipment							
1487			P	SG		3,683,986	1,620,862	3,683,986	1,620,862
1488			P	SG		3,374,661	1,484,766	3,374,661	1,484,766
1489			P	SG		67,056,294	29,503,092	67,056,294	29,503,092
1490			P	SG		10,763,264	4,735,567	10,763,264	4,735,567
1491					B8	84,878,205	37,344,287	84,878,205	37,344,287
1492									
1493									
1494									
1495	335	Misc. Power Plant Equipment							
1496			P	SG		1,130,832	497,538	1,130,832	497,538
1497			P	SG		155,552	68,439	155,552	68,439
1498			P	SG		1,166,322	513,152	1,166,322	513,152
1499			P	SG		18,279	8,042	18,279	8,042
1500					B8	2,470,985	1,087,171	2,470,985	1,087,171
1501									
1502	336	Roads, Railroads & Bridges							
1503			P	SG		4,333,284	1,906,536	4,333,284	1,906,536
1504			P	SG		770,862	339,160	770,862	339,160
1505			P	SG		18,344,615	8,071,172	18,344,615	8,071,172
1506			P	SG		1,431,463	629,808	1,431,463	629,808
1507					B8	24,880,224	10,946,676	24,880,224	10,946,676
1508									
1509	337	Hydro Plant ARO							
1510			P	S		-	-	-	-
1511					B8	-	-	-	-
1512									
1513	HP	Unclassified Hydro Plant - Acct 300							
1514			P	S		-	-	-	-
1515			P	SG		-	-	-	-
1516			P	SG		-	-	-	-
1517			P	SG		-	-	-	-
1518					B8	-	-	-	-
1519									
1520	**Total Hydraulic Production Plant**				**B8**	**1,077,728,210**	**474,173,449**	**1,112,189,220**	**489,335,431**
1521									
1522	Summary of Hydraulic Plant by Factor								
1523		S				-	-	-	-
1524		SG				1,077,728,210	474,173,449	1,112,189,220	489,335,431
1525		DGP				-	-	-	-
1526		DGU				-	-	-	-
1527	Total Hydraulic Plant by Factor					1,077,728,210	474,173,449	1,112,189,220	489,335,431
1528									
1529	340	Land and Land Rights							
1530			P	S		74,986	-	74,986	-
1531			P	SG		39,022,504	17,168,926	39,022,504	17,168,926
1532			P	SG		7,799,858	3,431,742	7,799,858	3,431,742
1533			P	SG		235,129	103,451	235,129	103,451
1534					B8	47,132,478	20,704,119	47,132,478	20,704,119
1535									
1536	341	Structures and Improvements							
1537			P	SG		170,249,153	74,905,368	170,249,153	74,905,368
1538			P	SG		-	-	-	-
1539			P	SG		54,141,555	23,820,930	54,141,555	23,820,930
1540			P	SG		4,273,000	1,880,013	4,273,000	1,880,013
1541					B8	228,663,709	100,606,311	228,663,709	100,606,311
1542									
1543	342	Fuel Holders, Producers & Accessories							
1544			P	SG		13,428,889	5,908,375	13,428,889	5,908,375
1545			P	SG		-	-	-	-
1546			P	SG		2,759,334	1,214,038	2,759,334	1,214,038
1547					B8	16,188,223	7,122,413	16,188,223	7,122,413

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	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2019 UNADJUSTED RESULTS TOTAL	DECEMBER 2019 UNADJUSTED RESULTS UTAH	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS UTAH
1548									
1549	343	Prime Movers							
1550			P	S		-	-	58,652	-
1551			P	SG		-	-	-	-
1552			P	SG		1,772,655,168	779,923,924	3,648,324,623	1,605,171,558
1553			P	SG		1,074,602,286	472,798,121	796,462,867	350,423,735
1554			P	SG		57,937,388	25,491,001	58,265,093	25,635,183
1555					B8	2,905,194,842	1,278,213,046	4,503,111,234	1,981,230,476
1556									
1557	344	Generators							
1558			P	S		-	-	-	-
1559			P	SG		62,293,764	27,407,698	62,293,764	27,407,698
1560			P	SG		400,771,759	176,329,547	400,771,759	176,329,547
1561			P	SG		17,782,763	7,823,971	17,782,763	7,823,971
1562					B8	480,848,285	211,561,215	480,848,285	211,561,215
1563									
1564	345	Accessory Electric Plant							
1565			P	SG		211,261,475	92,949,763	211,261,475	92,949,763
1566			P	SG		113,385,634	49,886,842	113,385,634	49,886,842
1567			P	SG		-	-	-	-
1568			P	SG		2,901,493	1,276,584	2,901,493	1,276,584
1569					B8	327,548,601	144,113,190	327,548,601	144,113,190
1570									
1571									
1572									
1573	346	Misc. Power Plant Equipment							
1574			P	SG		12,586,673	5,537,821	12,586,673	5,537,821
1575			P	SG		3,337,649	1,468,482	3,337,649	1,468,482
1576			P	SG		-	-	-	-
1577					B8	15,924,321	7,006,303	15,924,321	7,006,303
1578									
1579	347	Other Production ARO							
1580			P	S		-	-	-	-
1581					B8	-	-	-	-
1582									
1583	OP	Unclassified Other Prod Plant-Acct 300							
1584			P	S		-	-	-	-
1585			P	SG		(476,250)	(209,538)	(476,250)	(209,538)
1586						(476,250)	(209,538)	(476,250)	(209,538)
1587									
1588	**Total Other Production Plant**				**B8**	**4,021,024,209**	**1,769,117,060**	**5,618,940,601**	**2,472,134,489**
1589									
1590	Summary of Other Production Plant by Factor								
1591		S				74,986	-	133,637	-
1592		DGU				-	-	-	-
1593		SG				4,020,949,224	1,769,117,060	5,618,806,964	2,472,134,489
1594		SSGCT				-	-	-	-
1595	Total of Other Production Plant by Factor					4,021,024,209	1,769,117,060	5,618,940,601	2,472,134,489
1596									
1597	Experimental Plant								
1598	103	Experimental Plant							
1599			P	SG		-	-	-	-
1600	**Total Experimental Production Plant**				**B8**	**-**	**-**	**-**	**-**
1601									
1602	**Total Production Plant**				**B8**	**12,413,183,392**	**5,461,457,139**	**13,578,829,578**	**5,974,286,493**
1603	350	Land and Land Rights							
1604			T	SG		21,061,510	9,266,538	21,061,510	9,266,538
1605			T	SG		48,191,086	21,202,872	48,191,086	21,202,872
1606			T	SG		205,418,587	90,379,039	205,418,587	90,379,039
1607					B8	274,671,183	120,848,448	274,671,183	120,848,448
1608									
1609	352	Structures and Improvements							
1610			T	S		-	-	-	-
1611			T	SG		7,022,589	3,089,763	7,022,589	3,089,763
1612			T	SG		17,702,492	7,788,653	17,702,492	7,788,653
1613			T	SG		253,267,781	111,431,487	253,267,781	111,431,487
1614					B8	277,992,861	122,309,904	277,992,861	122,309,904
1615									
1616	353	Station Equipment							
1617			T	SG		106,185,098	46,718,786	106,185,098	46,718,786
1618			T	SG		154,078,561	67,790,712	154,078,561	67,790,712
1619			T	SG		1,939,486,318	853,325,456	1,939,486,318	853,325,456
1620					B8	2,199,749,976	967,834,955	2,199,749,976	967,834,955
1621									
1622	354	Towers and Fixtures							
1623			T	SG		128,108,873	56,364,699	128,108,873	56,364,699
1624			T	SG		131,291,888	57,765,146	131,291,888	57,765,146
1625			T	SG		1,043,574,207	459,146,542	1,043,574,207	459,146,542
1626					B8	1,302,974,969	573,276,388	1,302,974,969	573,276,388
1627									

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FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2019 UNADJUSTED RESULTS TOTAL	DECEMBER 2019 UNADJUSTED RESULTS UTAH	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS UTAH
355	Poles and Fixtures							
		T	SG		61,168,792	26,912,738	56,793,433	24,987,690
		T	SG		114,965,512	50,581,949	108,059,492	47,543,473
		T	SG		807,470,295	355,266,728	2,009,061,020	883,936,585
				B8	983,604,600	432,761,415	2,173,913,945	956,467,747
356	Clearing and Grading							
		T	SG		158,484,869	69,729,377	158,484,869	69,729,377
		T	SG		157,763,804	69,412,127	157,763,804	69,412,127
		T	SG		949,947,305	417,953,048	949,947,305	417,953,048
				B8	1,266,195,977	557,094,551	1,266,195,977	557,094,551
357	Underground Conduit							
		T	SG		6,371	2,803	6,371	2,803
		T	SG		91,651	40,324	91,651	40,324
		T	SG		3,603,014	1,585,236	3,603,014	1,585,236
				B8	3,701,035	1,628,363	3,701,035	1,628,363
358	Underground Conductors							
		T	SG		-	-	-	-
		T	SG		1,087,552	478,496	1,087,552	478,496
		T	SG		7,161,307	3,150,796	7,161,307	3,150,796
				B8	8,248,860	3,629,292	8,248,860	3,629,292
359	Roads and Trails							
		T	SG		1,863,032	819,687	1,863,032	819,687
		T	SG		440,513	193,815	440,513	193,815
		T	SG		9,633,656	4,238,567	9,633,656	4,238,567
				B8	11,937,200	5,252,070	11,937,200	5,252,070
TP	Unclassified Trans Plant - Acct 300							
		T	SG		107,229,090	47,178,117	107,229,090	47,178,117
				B8	107,229,090	47,178,117	107,229,090	47,178,117
TS0	Unclassified Trans Sub Plant - Acct 300							
		T	SG		-	-	-	-
				B8	-	-	-	-
Total Transmission Plant				**B8**	**6,436,305,751**	**2,831,813,503**	**7,626,615,097**	**3,355,519,835**
Summary of Transmission Plant by Factor								
		DGP			-	-	-	-
		DGU			-	-	-	-
		SG			6,436,305,751	2,831,813,503	7,626,615,097	3,355,519,835
Total Transmission Plant by Factor					6,436,305,751	2,831,813,503	7,626,615,097	3,355,519,835
360	Land and Land Rights							
		DPW	S		63,752,760	37,130,264	70,129,851	40,105,577
				B8	63,752,760	37,130,264	70,129,851	40,105,577
361	Structures and Improvements							
		DPW	S		121,761,254	57,871,589	133,940,847	63,554,133
				B8	121,761,254	57,871,589	133,940,847	63,554,133
362	Station Equipment							
		DPW	S		1,023,523,180	484,117,914	1,125,904,641	531,885,289
				B8	1,023,523,180	484,117,914	1,125,904,641	531,885,289
363	Storage Battery Equipment							
		DPW	S		-	-	-	-
				B8	-	-	-	-
364	Poles, Towers & Fixtures							
		DPW	S		1,234,275,935	398,812,506	1,357,738,672	456,415,619
				B8	1,234,275,935	398,812,506	1,357,738,672	456,415,619
365	Overhead Conductors							
		DPW	S		784,577,847	245,188,849	863,057,970	281,804,751
				B8	784,577,847	245,188,849	863,057,970	281,804,751
366	Underground Conduit							
		DPW	S		389,702,265	213,744,414	428,683,587	231,931,647
				B8	389,702,265	213,744,414	428,683,587	231,931,647
367	Underground Conductors							
		DPW	S		911,118,990	575,913,168	1,002,256,831	618,434,689
				B8	911,118,990	575,913,168	1,002,256,831	618,434,689

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	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2019 UNADJUSTED RESULTS TOTAL	DECEMBER 2019 UNADJUSTED RESULTS UTAH	DECEMBER 2021 NORMALIZED RESULTS TOTAL	DECEMBER 2021 NORMALIZED RESULTS UTAH
1706									
1707	368	Line Transformers							
1708			DPW	S		1,401,493,598	558,762,103	1,541,682,862	624,169,191
1709					B8	1,401,493,598	558,762,103	1,541,682,862	624,169,191
1710									
1711	369	Services							
1712			DPW	S		839,103,922	334,813,450	923,038,206	373,974,060
1713					B8	839,103,922	334,813,450	923,038,206	373,974,060
1714									
1715	370	Meters							
1716			DPW	S		236,587,441	91,938,159	260,252,921	102,979,590
1717					B8	236,587,441	91,938,159	260,252,921	102,979,590
1718									
1719	371	Installations on Customers' Premises							
1720			DPW	S		8,803,801	4,229,239	9,684,432	4,640,109
1721					B8	8,803,801	4,229,239	9,684,432	4,640,109
1722									
1723	372	Leased Property							
1724			DPW	S		-	-	-	-
1725					B8	-	-	-	-
1726									
1727	373	Street Lights							
1728			DPW	S		62,644,883	21,547,099	68,911,155	24,470,708
1729					B8	62,644,883	21,547,099	68,911,155	24,470,708
1730									
1731	DP	Unclassified Dist Plant - Acct 300							
1732			DPW	S		66,957,822	27,861,499	66,957,822	27,861,499
1733					B8	66,957,822	27,861,499	66,957,822	27,861,499
1734									
1735	DS0	Unclassified Dist Sub Plant - Acct 300							
1736			DPW	S		-	-	-	-
1737					B8	-	-	-	-
1738									
1739									
1740	**Total Distribution Plant**				**B8**	**7,144,303,698**	**3,051,930,252**	**7,852,239,797**	**3,382,226,861**
1741									
1742	Summary of Distribution Plant by Factor								
1743		S				7,144,303,698	3,051,930,252	7,852,239,797	3,382,226,861
1744									
1745	Total Distribution Plant by Factor					7,144,303,698	3,051,930,252	7,852,239,797	3,382,226,861
1746	389	Land and Land Rights							
1747			G-SITUS	S		14,330,816	4,080,600	14,330,816	4,080,600
1748			CUST	CN		1,128,506	539,532	1,128,506	539,532
1749			G-DGU	SG		332	146	332	146
1750			G-SG	SG		1,228	540	1,228	540
1751			PTD	SO		7,516,302	3,261,965	7,516,302	3,276,709
1752					B8	22,977,184	7,882,782	22,977,184	7,897,526
1753									
1754	390	Structures and Improvements							
1755			G-SITUS	S		132,917,235	44,198,383	132,917,235	44,198,383
1756			G-DGP	SG		335,238	147,496	335,238	147,496
1757			G-DGU	SG		1,482,919	652,447	1,482,919	652,447
1758			CUST	CN		8,202,037	3,921,344	8,202,037	3,921,344
1759			G-SG	SG		5,801,798	2,552,646	5,801,798	2,552,646
1760			P	SE		1,293,096	560,637	1,293,096	560,637
1761			PTD	SO		96,666,534	41,951,855	96,666,534	42,141,474
1762					B8	246,698,857	93,984,810	246,698,857	94,174,429
1763									
1764	391	Office Furniture & Equipment							
1765			G-SITUS	S		6,506,522	1,206,258	6,506,522	1,206,258
1766			G-DGP	SG		-	-	-	-
1767			G-DGU	SG		-	-	-	-
1768			CUST	CN		4,259,760	2,036,566	4,259,760	2,036,566
1769			G-SG	SG		3,325,340	1,463,066	3,325,340	1,463,066
1770			P	SE		10,545	4,572	10,545	4,572
1771			PTD	SO		55,974,566	24,292,139	55,974,566	24,401,938
1772			G-SG	SG		-	-	-	-
1773			G-SG	SG		4,039	1,777	4,039	1,777
1774					B8	70,080,773	29,004,379	70,080,773	29,114,177

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1775									
1776	392	Transportation Equipment							
1777			G-SITUS	S		88,213,062	37,167,013	88,213,062	37,167,013
1778			PTD	SO		7,114,838	3,087,735	7,114,838	3,101,691
1779			G-SG	SG		21,245,933	9,347,679	21,245,933	9,347,679
1780			CUST	CN		-	-	-	-
1781			G-DGU	SG		472,987	208,103	472,987	208,103
1782			P	SE		500,747	217,105	500,747	217,105
1783			G-DGP	SG		70,616	31,069	70,616	31,069
1784			G-SG	SG		299,519	131,781	299,519	131,781
1785			G-DGU	SG		44,655	19,647	44,655	19,647
1786					B8	117,962,357	50,210,132	117,962,357	50,224,088
1787									
1788	393	Stores Equipment							
1789			G-SITUS	S		8,533,070	3,306,767	8,533,070	3,306,767
1790			G-DGP	SG		-	-	-	-
1791			G-DGU	SG		-	-	-	-
1792			PTD	SO		255,085	110,703	255,085	111,203
1793			G-SG	SG		5,849,438	2,573,606	5,849,438	2,573,606
1794			G-DGU	SG		53,971	23,746	53,971	23,746
1795					B8	14,691,564	6,014,823	14,691,564	6,015,323
1796									
1797	394	Tools, Shop & Garage Equipment							
1798			G-SITUS	S		34,924,628	14,454,152	34,924,628	14,454,152
1799			G-DGP	SG		93,867	41,299	93,867	41,299
1800			G-SG	SG		22,399,543	9,855,238	22,399,543	9,855,238
1801			PTD	SO		2,208,108	958,286	2,208,108	962,618
1802			P	SE		109,750	47,584	109,750	47,584
1803			G-DGU	SG		-	-	-	-
1804			G-SG	SG		1,718,615	756,148	1,718,615	756,148
1805			G-SG	SG		89,913	39,560	89,913	39,560
1806					B8	61,544,425	26,152,267	61,544,425	26,156,598
1807									
1808	395	Laboratory Equipment							
1809			G-SITUS	S		21,630,155	7,906,771	21,630,155	7,906,771
1810			G-DGP	SG		-	-	-	-
1811			G-DGU	SG		-	-	-	-
1812			PTD	SO		4,958,344	2,151,849	4,958,344	2,161,575
1813			P	SE		1,261,169	546,795	1,261,169	546,795
1814			G-SG	SG		6,336,394	2,787,855	6,336,394	2,787,855
1815			G-SG	SG		223,587	98,373	223,587	98,373
1816			G-SG	SG		14,022	6,169	14,022	6,169
1817					B8	34,423,671	13,497,811	34,423,671	13,507,538
1818									
1819	396	Power Operated Equipment							
1820			G-SITUS	S		136,448,154	50,541,225	136,448,154	50,541,225
1821			G-DGP	SG		277,141	121,935	277,141	121,935
1822			G-SG	SG		44,145,185	19,422,777	44,145,185	19,422,777
1823			PTD	SO		6,711,775	2,912,812	6,711,775	2,925,977
1824			G-DGU	SG		1,057,504	465,275	1,057,504	465,275
1825			P	SE		249,547	108,194	249,547	108,194
1826			P	SG		-	-	-	-
1827			G-SG	SG		1,374,378	604,692	1,374,378	604,692
1828					B8	190,263,684	74,176,910	190,263,684	74,190,076
1829	397	Communication Equipment							
1830			G-SITUS	S		203,253,989	63,203,007	255,329,004	90,984,209
1831			G-DGP	SG		412,544	181,509	191,266	84,152
1832			G-DGU	SG		1,136,750	500,142	881,823	387,980
1833			PTD	SO		93,463,016	40,561,576	115,563,677	50,379,625
1834			CUST	CN		3,848,526	1,839,957	1,451,802	694,098
1835			G-SG	SG		175,994,453	77,433,156	192,909,825	84,875,497
1836			P	SE		343,512	148,934	458,537	198,804
1837			G-SG	SG		1,285,815	565,726	1,072,509	471,877
1838			G-SG	SG		16,633	7,318	16,633	7,318
1839					B8	479,755,238	184,441,324	567,875,075	228,083,560
1840									
1841	398	Misc. Equipment							
1842			G-SITUS	S		3,035,497	1,354,673	3,035,497	1,354,673
1843			G-DGP	SG		-	-	-	-
1844			G-DGU	SG		-	-	-	-
1845			CUST	CN		79,001	37,770	79,001	37,770
1846			PTD	SO		2,223,286	964,874	2,223,286	969,235
1847			P	SE		4,009	1,738	4,009	1,738
1848			G-SG	SG		2,698,795	1,187,402	2,698,795	1,187,402
1849			G-SG	SG		-	-	-	-
1850					B8	8,040,588	3,546,457	8,040,588	3,550,818

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1851									
1852	399	Coal Mine							
1853			P	SE		1,854,828	804,183	79,104,519	34,296,721
1854	MP		P	SE		-	-	-	-
1855					B8	1,854,828	804,183	79,104,519	34,296,721
1856									
1857	399L	WIDCO Capital Lease							
1858			P	SE		-	-	-	-
1859						-	-	-	-
1860									
1861		Remove Capital Leases				-	-	-	-
1862						-	-	-	-
1863									
1864	1011390	General Capital Leases							
1865			G-SITUS	S		5,563,333	3,475,886	5,563,333	3,475,886
1866			P	SG		10,774,085	4,740,328	10,774,085	4,740,328
1867			PTD	SO		1,708,906	741,640	1,708,906	744,992
1868					B9	18,046,324	8,957,854	18,046,324	8,961,206
1869									
1870		Remove Capital Leases				(18,046,324)	(8,957,854)	(18,046,324)	(8,961,206)
1871						-	-	-	-
1872									
1873	1011346	General Gas Line Capital Leases							
1874			P	SG		-	-	-	-
1875					B9	-	-	-	-
1876									
1877		Remove Capital Leases				-	-	-	-
1878						-	-	-	-
1879									
1880	GP	Unclassified Gen Plant - Acct 300							
1881			G-SITUS	S		-	-	-	-
1882			PTD	SO		36,905,928	16,016,631	36,905,928	16,089,024
1883			CUST	CN		-	-	-	-
1884			G-SG	SG		-	-	-	-
1885			G-DGP	SG		-	-	-	-
1886			G-DGU	SG		-	-	-	-
1887					B8	36,905,928	16,016,631	36,905,928	16,089,024
1888									
1889	399G	Unclassified Gen Plant - Acct 300							
1890			G-SITUS	S		-	-	-	-
1891			PTD	SO		-	-	-	-
1892			G-SG	SG		-	-	-	-
1893			G-DGP	SG		-	-	-	-
1894			G-DGU	SG		-	-	-	-
1895					B8	-	-	-	-
1896									
1897	**Total General Plant**				**B8**	**1,285,199,097**	**505,732,508**	**1,450,568,624**	**583,299,877**
1898									
1899	Summary of General Plant by Factor								
1900		S				655,356,462	230,894,736	707,431,477	258,675,938
1901		DGP				-	-	-	-
1902		DGU				-	-	-	-
1903		SG				309,037,237	135,968,653	325,263,098	143,107,625
1904		SO				315,706,687	137,012,063	337,807,349	147,266,061
1905		SE				5,627,203	2,439,742	82,991,919	35,982,150
1906		CN				17,517,830	8,375,169	15,121,106	7,229,309
1907		DEU				-	-	-	-
1908		SSGCT				-	-	-	-
1909		SSGCH				-	-	-	-
1910		Less Capital Leases				(18,046,324)	(8,957,854)	(18,046,324)	(8,961,206)
1911	Total General Plant by Factor					1,285,199,097	505,732,508	1,450,568,624	583,299,877
1912	301	Organization							
1913			I-SITUS	S		-	-	-	-
1914			PTD	SO		-	-	-	-
1915			I-SG	SG		-	-	-	-
1916					B8	-	-	-	-
1917	302	Franchise & Consent							
1918			I-SITUS	S		(31,081,215)	(32,081,215)	1,000,000	-
1919			I-SG	SG		10,337,537	4,548,258	15,402,661	6,776,786
1920			I-SG	SG		175,266,123	77,112,709	101,048,859	44,458,970
1921			I-SG	SG		9,350,399	4,113,942	9,350,399	4,113,942
1922			I-DGP	SG		-	-	-	-
1923			I-DGU	SG		600,993	264,422	600,993	264,422
1924					B8	164,473,837	53,958,115	127,402,912	55,614,119

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1925									
1926	303	Miscellaneous Intangible Plant							
1927			I-SITUS	S		22,022,388	5,890,217	22,981,472	6,140,225
1928			I-SG	SG		172,346,397	75,828,103	176,813,627	77,793,572
1929			PTD	SO		390,075,918	169,287,217	413,459,279	180,246,284
1930			P	SE		-	-	(1,106,269)	(479,636)
1931			CUST	CN		176,932,374	84,590,299	183,528,366	87,743,803
1932			P	SG		-	-	-	-
1933			I-DGP	SG		-	-	-	-
1934					B8	761,377,077	335,595,835	795,676,475	351,444,248
1935	303	Less Non-Regulated Plant							
1936			I-SITUS	S		-	-	-	-
1937						761,377,077	335,595,835	795,676,475	351,444,248
1938	IP	Unclassified Intangible Plant - Acct 300							
1939			I-SITUS	S		-	-	-	-
1940			I-SG	SG		-	-	-	-
1941			I-DGU	SG		-	-	-	-
1942			PTD	SO		-	-	-	-
1943						-	-	-	-
1944									
1945	**Total Intangible Plant**				**B8**	**925,850,914**	**389,553,950**	**923,079,388**	**407,058,367**
1946									
1947	Summary of Intangible Plant by Factor								
1948		S				(9,058,827)	(26,190,998)	23,981,472	6,140,225
1949		DGP				-	-	-	-
1950		DGU				-	-	-	-
1951		SG				367,901,449	161,867,433	303,216,540	133,407,691
1952		SO				390,075,918	169,287,217	413,459,279	180,246,284
1953		CN				176,932,374	84,590,299	183,528,366	87,743,803
1954		SSGCT				-	-	-	-
1955		SSGCH				-	-	-	-
1956		SE				-	-	(1,106,269)	(479,636)
1957	Total Intangible Plant by Factor					925,850,914	389,553,950	923,079,388	407,058,367
1958	Summary of Unclassified Plant (Account 106)								
1959		DP				66,957,822	27,861,499	66,957,822	27,861,499
1960		DS0				-	-	-	-
1961		GP				36,905,928	16,016,631	36,905,928	16,089,024
1962		HP				-	-	-	-
1963		NP				-	-	-	-
1964		OP				(476,250)	(209,538)	(476,250)	(209,538)
1965		TP				107,229,090	47,178,117	107,229,090	47,178,117
1966		TS0				-	-	-	-
1967		IP				-	-	-	-
1968		MP				-	-	-	-
1969		SP				46,348,779	20,392,303	46,348,779	20,392,303
1970	Total Unclassified Plant by Factor					256,965,369	111,239,011	256,965,369	111,311,405
1971									
1972	**Total Electric Plant In Service**				**B8**	**28,204,842,852**	**12,240,487,353**	**31,431,332,484**	**13,702,391,432**
1973	Summary of Electric Plant by Factor								
1974		S				7,790,676,319	3,256,633,990	8,583,786,383	3,647,043,024
1975		SE				5,627,203	2,439,742	81,885,650	35,502,514
1976		DGU				-	-	-	-
1977		DGP				-	-	-	-
1978		SG				19,526,352,844	8,591,106,728	21,833,790,675	9,606,321,644
1979		SO				705,782,605	306,299,280	751,266,628	327,512,345
1980		CN				194,450,204	92,965,467	198,649,472	94,973,112
1981		DEU				-	-	-	-
1982		SSGCH				-	-	-	-
1983		SSGCT				-	-	-	-
1984		Less Capital Leases				(18,046,324)	(8,957,854)	(18,046,324)	(8,961,206)
1985						28,204,842,852	12,240,487,353	31,431,332,484	13,702,391,432
1986	105	Plant Held For Future Use							
1987			DPW	S		13,593,785	5,730,529	13,593,785	5,730,529
1988			P	SG		-	-	-	-
1989			T	SG		3,657,534	1,609,224	3,657,534	1,609,224
1990			P	SG		8,923,302	3,926,029	8,923,302	3,926,029
1991			P	SE		-	-	-	-
1992			G	SG		-	-	(11,155,675)	(4,908,218)
1993									
1994									
1995	**Total Plant Held For Future Use**				**B10**	**26,174,621**	**11,265,782**	**15,018,946**	**6,357,564**
1996									
1997	114	Electric Plant Acquisition Adjustments							
1998			P	S		11,763,784	11,763,784	11,763,784	11,763,784
1999			P	SG		144,704,699	63,666,447	144,704,699	63,666,447
2000			P	SG		-	-	-	-
2001	**Total Electric Plant Acquisition Adjustment**				**B15**	**156,468,483**	**75,430,231**	**156,468,483**	**75,430,231**

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2002									
2003	115	Accum Provision for Asset Acquisition Adjustments							
2004			P	S		(1,294,270)	(1,294,270)	(1,897,541)	(1,897,541)
2005			P	SG		(128,417,358)	(56,500,425)	(141,862,798)	(62,416,082)
2006			P	SG		-	-	-	-
2007					B15	(129,711,629)	(57,794,695)	(143,760,340)	(64,313,623)
2008									
2009	128	Pensions							
2010			LABOR	SO		4,464,716	1,937,621	34,843,256	15,189,809
2011	**Total Pensions**				**B15**	**4,464,716**	**1,937,621**	**34,843,256**	**15,189,809**
2012									
2013	124	Weatherization							
2014			DMSC	S		789,162	4,492	784,669	-
2015			DMSC	SO		(5,008)	(2,173)	(1)	(1)
2016					B16	784,154	2,319	784,668	(1)
2017									
2018	182W	Weatherization							
2019			DMSC	S		(12,349,609)	-	(12,349,609)	-
2020			DMSC	SG		-	-	-	-
2021			DMSC	SGCT		-	-	-	-
2022			DMSC	SO		-	-	-	-
2023					B16	(12,349,609)	-	(12,349,609)	-
2024									
2025	186W	Weatherization							
2026			DMSC	S		-	-	-	-
2027			DMSC	CN		-	-	-	-
2028			DMSC	CNP		-	-	-	-
2029			DMSC	SG		-	-	-	-
2030			DMSC	SO		-	-	-	-
2031					B16	-	-	-	-
2032									
2033	**Total Weatherization**				**B16**	**(11,565,455)**	**2,319**	**(11,564,941)**	**(1)**
2034									
2035	151	Fuel Stock							
2036			P	DEU		-	-	-	-
2037			P	SE		163,859,900	71,043,442	167,007,551	72,408,144
2038			P	SE		-	-	-	-
2039			P	SE		9,237,440	4,005,004	9,237,440	4,005,004
2040					B13	173,097,340	75,048,445	176,244,990	76,413,147
2041									
2042	152	Fuel Stock - Undistributed							
2043			P	SE		-	-	-	-
2044						-	-	-	-
2045									
2046	25316	UAMPS Working Capital Deposit							
2047			P	SE		(2,496,462)	(1,082,371)	(2,063,462)	(894,639)
2048					B13	(2,496,462)	(1,082,371)	(2,063,462)	(894,639)
2049									
2050	25317	DG&T Working Capital Deposit							
2051			P	SE		(2,620,035)	(1,135,948)	(2,707,857)	(1,174,024)
2052					B13	(2,620,035)	(1,135,948)	(2,707,857)	(1,174,024)
2053									
2054	25319	Provo Working Capital Deposit							
2055			P	SE		-	-	-	-
2056						-	-	-	-
2057									
2058	**Total Fuel Stock**				**B13**	**167,980,844**	**72,830,126**	**171,473,671**	**74,344,484**
2059	154	Materials and Supplies							
2060			MSS	S		117,863,706	47,854,931	117,863,706	47,854,931
2061			MSS	SG		4,906,248	2,158,627	(1,759,728)	(774,236)
2062			MSS	SE		-	-	-	-
2063			MSS	SO		(66,993)	(29,074)	(66,993)	(29,205)
2064			MSS	SG		116,002,537	51,038,214	116,002,537	51,038,214
2065			MSS	SG		7,850	3,454	7,850	3,454
2066			MSS	SNPD		(1,650,835)	(796,217)	(1,650,835)	(796,004)
2067			MSS	SG		-	-	-	-
2068			MSS	SG		-	-	-	-
2069			MSS	SG		-	-	-	-
2070			MSS	SG		-	-	-	-
2071			MSS	SG		9,406,485	4,138,618	9,406,485	4,138,618
2072			MSS	SG		-	-	-	-
2073					B13	246,468,997	104,368,552	239,803,021	101,435,772
2074									
2075	163	Stores Expense Undistributed							
2076			MSS	SO		-	-	-	-
2077									
2078					B13	-	-	-	-

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25318	Provo Working Capital Deposit							
		MSS	SG		(273,000)	(120,113)	(273,000)	(120,113)
				B13	(273,000)	(120,113)	(273,000)	(120,113)
Total Materials and Supplies				**B13**	**246,195,997**	**104,248,439**	**239,530,021**	**101,315,658**
165	Prepayments							
		DMSC	S		19,471,435	3,352,695	19,471,435	3,352,695
		GP	GPS		5,839,642	2,534,319	5,839,642	2,545,774
		PT	SG		3,344,629	1,471,553	3,344,629	1,471,553
		P	SE		3,590	1,556	3,590	1,556
		PTD	SO		20,800,417	9,027,076	20,800,417	9,067,877
Total Prepayments				**B15**	**49,459,714**	**16,387,199**	**49,459,714**	**16,439,455**
182M	Misc Regulatory Assets							
		DDS2	S		120,386,087	7,822,371	105,645,523	1,717,933
		DEFSG	SG		3,448,669	1,517,328	24,381,831	10,727,396
		P	SGCT		-	-	-	-
		DEFSG	SG-P		-	-	-	-
		P	SE		185,893,860	80,596,531	115,119,099	49,911,278
		P	SG		-	-	-	-
		DDSO2	SO		471,492,792	204,620,943	360,486,168	157,152,821
				B16	781,221,408	294,557,174	605,632,622	219,509,428
186M	Misc Deferred Debits							
		LABOR	S		3,528,662	-	3,528,662	-
		P	SG		-	-	-	-
		P	SG		-	-	-	-
		DEFSG	SG		81,170,053	35,712,793	87,713,639	38,591,807
		LABOR	SO		281,966	122,369	281,966	122,922
		P	SE		1,760,630	763,343	1,760,630	763,343
		P	SG		-	-	-	-
		GP	EXCTAX		-	-	-	-
Total Misc. Deferred Debits				**B11**	**86,741,312**	**36,598,504**	**93,284,898**	**39,478,072**
Working Capital								
CWC	Cash Working Capital							
		CWC	S		29,065,417	15,230,221	24,987,810	13,119,414
		CWC	SO		-	-	-	-
		CWC	SE		-	-	-	-
					29,065,417	15,230,221	24,987,810	13,119,414
OWC	Other Work. Cap.							
131	Cash	GP	SNP		-	-	-	-
135	Working Funds	GP	SG		-	-	-	-
141	Notes Receivabl	GP	SO		-	-	-	-
143	Other A/R	GP	SO		39,073,062	16,957,135	39,073,062	17,033,779
232	A/P	PTD	S		(15,475)	-	(15,475)	-
232	A/P	PTD	SO		(6,992,292)	(3,034,552)	(6,992,292)	(3,048,268)
232	A/P	P	SE		(1,732,589)	(751,185)	(1,732,589)	(751,185)
232	A/P	T	SG		(2,987,663)	(1,314,497)	(2,987,663)	(1,314,497)
2533	Other Msc. Df. Crd.	P	S		-	-	-	-
2533	Other Msc. Df. Crd.	P	SE		(6,633,774)	(2,876,153)	(7,155,387)	(3,102,305)
230	Asset Retir. Oblig.	P	SG		-	-	-	-
230	Asset Retir. Oblig.	P	S		(5,559,148)	-	(5,559,148)	-
254	ARO Reg Liability	P	SG		-	-	(19,380,226)	(8,526,815)
254	ARO Reg Liability	P	TROJD		-	-	-	-
2533	Cholla Reclamation	P	SE		-	-	-	-
				B14	15,152,121	8,980,748	(4,749,719)	290,710
Total Working Capital				**B14**	**44,217,537**	**24,210,969**	**20,238,091**	**13,410,124**
Miscellaneous Rate Base								
18221	Unrec Plant & Reg Study Costs							
		P	S		-	-	-	-
					-	-	-	-
18222	Nuclear Plant - Trojan							
		P	S		-	-	-	-
		P	TROJP		-	-	-	-
		P	TROJD		-	-	-	-
				B16	-	-	-	-

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2153									
2154									
2155									
2156	1869	Misc Deferred Debits-Trojan							
2157			P	S		-	-	-	-
2158			P	SG		-	-	-	-
2159						-	-	-	-
2160									
2161	**Total Miscellaneous Rate Base**				**B15**	**-**	**-**	**-**	**-**
2162									
2163	**Total Rate Base Additions**					**1,421,647,548**	**579,673,670**	**1,230,624,421**	**497,161,202**
2164	235	Customer Service Deposits							
2165			CUST	S		-	-	(16,275,584)	(16,275,584)
2166			CUST	CN		-	-	-	-
2167	**Total Customer Service Deposits**				B15	**-**	**-**	**(16,275,584)**	**(16,275,584)**
2168									
2169	2281	Prop Ins	PTD	S		(9,183,079)	(7,461,027)	(9,183,079)	(7,461,027)
2170	2282	Inj & Dam	PTD	SO		(14,440,726)	(6,267,063)	0	0
2171	2283	Pen & Ben	PTD	SO		(99,332,332)	(43,108,772)	(32,345,479)	(14,100,911)
2172	254	Reg Liab Pos	PTD	SO		(1,411,893)	(612,741)	(1,411,893)	(615,510)
2173	2282	Prov for Injur	PTD	S		(8,710,935)	-	(8,710,935)	-
2174	25335	Reg Liabilitie	PTD	SE		(115,119,099)	(49,911,278)	(115,119,099)	(49,911,278)
2175					B15	(248,198,063)	(107,360,880)	(166,770,485)	(72,088,726)
2176									
2177	22841	Accum Misc. Operating Provisions							
2178			P	S		-	-	-	-
2179			P	SG		(479,880)	(211,135)	(479,880)	(211,135)
2180					B15	(479,880)	(211,135)	(479,880)	(211,135)
2181									
2182	254105	ARO	P	S		257,471	-	257,471	-
2183	230	ARO	P	TROJD		(2,966,557)	(1,301,810)	(2,966,557)	(1,301,810)
2184	254105	ARO	P	TROJD		(2,402,450)	(1,054,264)	-	-
2185	254		P	S		(547,654,081)	(93,001,993)	(1,118,691,212)	(664,039,125)
2186					B15	(552,765,617)	(95,358,068)	(1,121,400,298)	(665,340,935)
2187									
2188	252	Customer Advances for Construction							
2189			DPW	S		(6,700,608)	(1,518,089)	(16,678,157)	(12,671,502)
2190			DPW	SE		-	-	-	-
2191			T	SG		(67,641,413)	(29,760,530)	(57,663,864)	(25,370,658)
2192			DPW	SO		-	-	-	-
2193			CUST	CN		-	-	-	-
2194	**Total Customer Advances for Construction**				**B20**	**(74,342,021)**	**(31,278,618)**	**(74,342,021)**	**(38,042,160)**
2195									
2196	25398	SO2 Emissions							
2197			P	SE		-	-	-	-
2198						-	-	-	-
2199									
2200	25399	Other Deferred Credits							
2201			P	S		(2,865,055)	(870,565)	(2,865,055)	(870,565)
2202			LABOR	SO		(56,400,465)	(24,476,973)	(56,400,465)	(24,587,607)
2203			P	SG		(21,447,465)	(9,436,348)	(21,447,465)	(9,436,348)
2204			P	SE		(7,493,406)	(3,248,857)	(7,493,406)	(3,248,857)
2205					B15	(88,206,391)	(38,032,743)	(88,206,391)	(38,143,376)
2206									
2207	190	Accumulated Deferred Income Taxes							
2208			P	S		114,784,693	23,384,377	242,278,981	165,161,985
2209			CUST	CN		-	-	-	-
2210			LABOR	SO		108,617,291	47,138,308	68,466,709	29,847,848
2211			P	DGP		-	-	-	-
2212			IBT	IBT		-	-	-	-
2213			P	SG		-	-	-	-
2214			P	SG		-	-	-	-
2215			CUST	BADDEBT		2,519,957	837,081	2,754,659	897,660
2216			P	TROJD		1,320,056	579,278	0	0
2217			P	SG		26,179,267	11,518,222	6,214,125	2,734,060
2218			P	SE		22,061,147	9,564,877	(5,607,875)	(2,431,362)
2219			PTD	SNP		-	-	-	-
2220			DPW	SNPD		1,378,866	665,043	1,932,611	931,871
2221			P	SG		-	-	-	-
2222					B19	276,861,276	93,687,186	316,039,210	197,142,062
2223									
2224	281	Accumulated Deferred Income Taxes							
2225			P	S		-	-	-	-
2226			PT	SG		(177,382,631)	(78,043,920)	(0)	(0)
2227			T	SG		-	-	-	-
2228					B19	(177,382,631)	(78,043,920)	(0)	(0)

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282	Accumulated Deferred Income Taxes							
		GP	S		(71,261,625)	(2,181,173)	(2,819,269,804)	(1,250,786,694)
		ACCMDIT	DITBAL		(3,886,209,063)	(1,712,498,963)	1	1
		PT	SNP		-	-	-	-
		LABOR	SO		(1,044,722)	(453,394)	(525,978)	(229,299)
		PTD	GPS		-	-	-	-
		DPW	CIAC		-	-	-	-
		P	SNPD		-	-	-	-
		GP	SCHMDEXP		-	-	-	-
		TAXDEPR	TAXDEPR		-	-	-	-
		P	DGP		-	-	-	-
		PT	IBT		-	-	-	-
		PT	SG		-	-	-	-
		P	SG		-	-	-	-
		P	SE		(6,628,459)	(2,873,849)	(2,637,201)	(1,143,390)
		P	SG		(819,786)	(360,685)	(137,555,618)	(60,521,031)
				B19	(3,965,963,655)	(1,718,368,064)	(2,959,988,599)	(1,312,680,413)
283	Accumulated Deferred Income Taxes							
		GP	S		(33,275,213)	(5,181,380)	(86,565,242)	(1,987,949)
		P	SG		(1,766,839)	(777,365)	(6,796,221)	(2,990,167)
		P	SE		(42,609,508)	(18,473,868)	(1)	(0)
		LABOR	SO		(131,281,233)	(56,974,126)	(93,247,894)	(40,651,129)
		GP	GPS		(6,821,897)	(2,960,603)	(6,821,149)	(2,973,659)
		PTD	SNP		(1,048,063)	(469,917)	(764,589)	(337,992)
		P	TROJD		-	-	-	-
		P	SG		-	-	-	-
		P	SG		-	-	-	-
		P	SG		-	-	-	-
				B19	(216,802,753)	(84,837,259)	(194,195,097)	(48,940,896)
Total Accum Deferred Income Tax				**B19**	**(4,083,287,763)**	**(1,787,562,057)**	**(2,838,144,486)**	**(1,164,479,247)**
255	Accumulated Investment Tax Credit							
		PTD	S		(38,401)	-	(28,187)	-
		PTD	ITC84		-	-	-	-
		PTD	ITC85		-	-	-	-
		PTD	ITC86		-	-	-	-
		PTD	ITC88		-	-	-	-
		PTD	ITC89		-	-	-	-
		PTD	ITC90		(42,534)	(19,964)	-	-
		PTD	SG		(216,528)	(95,267)	(193,141)	(84,977)
Total Accumulated ITC				**B19**	**(297,463)**	**(115,230)**	**(221,328)**	**(84,977)**
Total Rate Base Deductions					**(5,047,577,197)**	**(2,059,918,731)**	**(4,305,840,472)**	**(1,994,666,140)**
108SP	Steam Prod Plant Accumulated Depr							
		P	S		10,846,025	8,871,391	(220,924,579)	(222,899,213)
		P	SG		(765,397,082)	(336,755,567)	(825,600,764)	(363,243,681)
		P	SG		(736,317,493)	(323,961,275)	(779,379,519)	(342,907,489)
		P	SG		(1,490,892,214)	(655,955,274)	(1,482,741,438)	(652,369,136)
		P	SG		-	-	-	-
		P	SG		(246,500,340)	(108,453,983)	(266,435,549)	(117,224,976)
				B17	(3,228,261,105)	(1,416,254,708)	(3,575,081,849)	(1,698,644,495)
108NP	Nuclear Prod Plant Accumulated Depr							
		P	SG		-	-	-	-
		P	SG		-	-	-	-
		P	SG		-	-	-	-
				B17	-	-	-	-
108HP	Hydraulic Prod Plant Accum Depr							
		P	S		3,600,961	-	3,600,961	-
		P	SG		(174,168,301)	(76,629,695)	(149,229,814)	(65,657,385)
		P	SG		(30,652,422)	(13,486,299)	(32,759,104)	(14,413,186)
		P	SG		(190,913,454)	(83,997,143)	(246,145,375)	(108,297,807)
		P	SG		(51,878,311)	(22,825,159)	(62,463,830)	(27,482,523)
				B17	(444,011,527)	(196,938,296)	(486,997,163)	(215,850,900)
108OP	Other Production Plant - Accum Depr							
		P	S		-	-	-	-
		P	SG		-	-	-	-
		P	SG		(592,873,211)	(260,849,380)	368,629,279	162,187,660
		P	SG		(418,247,158)	(184,018,286)	(493,255,119)	(217,019,912)
		P	SG		(36,897,464)	(16,233,961)	(42,818,301)	(18,838,981)
				B17	(1,048,017,834)	(461,101,627)	(167,444,140)	(73,671,232)

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2309	108EP	Experimental Plant - Accum Depr							
2310			P	SG		-	-	-	-
2311			P	SG		-	-	-	-
2312						-	-	-	-
2313									
2314	**Total Production Plant Accum Depreciation**				**B17**	**(4,720,290,466)**	**(2,074,294,631)**	**(4,229,523,152)**	**(1,988,166,628)**
2315									
2316	Summary of Prod Plant Depreciation by Factor								
2317		S				14,446,986	8,871,391	(217,323,618)	(222,899,213)
2318		DGP				-	-	-	-
2319		DGU				-	-	-	-
2320		SG				(4,734,737,452)	(2,083,166,022)	(4,012,199,534)	(1,765,267,415)
2321		SSGCH				-	-	-	-
2322		SSGCT				-	-	-	-
2323	Total of Prod Plant Depreciation by Factor					(4,720,290,466)	(2,074,294,631)	(4,229,523,152)	(1,988,166,628)
2324									
2325									
2326	108TP	Transmission Plant Accumulated Depr							
2327			T	SG		(354,052,614)	(155,774,292)	(369,846,223)	(162,723,085)
2328			T	SG		(421,321,086)	(185,370,737)	(439,311,441)	(193,286,043)
2329			T	SG		(1,040,008,905)	(457,577,899)	(1,204,114,192)	(529,780,119)
2330	**Total Trans Plant Accum Depreciation**				**B17**	**(1,815,382,605)**	**(798,722,928)**	**(2,013,271,856)**	**(885,789,247)**
2331	108360	Land and Land Rights							
2332			DPW	S		(10,259,439)	(3,261,422)	(12,375,097)	(4,186,907)
2333					B17	(10,259,439)	(3,261,422)	(12,375,097)	(4,186,907)
2334									
2335	108361	Structures and Improvements							
2336			DPW	S		(28,140,795)	(12,356,248)	(32,181,484)	(14,123,829)
2337					B17	(28,140,795)	(12,356,248)	(32,181,484)	(14,123,829)
2338									
2339	108362	Station Equipment							
2340			DPW	S		(292,674,478)	(119,864,354)	(326,640,446)	(134,722,607)
2341					B17	(292,674,478)	(119,864,354)	(326,640,446)	(134,722,607)
2342									
2343	108363	Storage Battery Equipment							
2344			DPW	S		-	-	-	-
2345					B17	-	-	-	-
2346									
2347	108364	Poles, Towers & Fixtures							
2348			DPW	S		(661,645,540)	(158,107,265)	(702,605,410)	(176,024,967)
2349					B17	(661,645,540)	(158,107,265)	(702,605,410)	(176,024,967)
2350									
2351	108365	Overhead Conductors							
2352			DPW	S		(336,071,639)	(87,096,717)	(362,108,124)	(98,486,255)
2353					B17	(336,071,639)	(87,096,717)	(362,108,124)	(98,486,255)
2354									
2355	108366	Underground Conduit							
2356			DPW	S		(171,275,138)	(83,102,264)	(184,207,541)	(88,759,483)
2357					B17	(171,275,138)	(83,102,264)	(184,207,541)	(88,759,483)
2358									
2359	108367	Underground Conductors							
2360			DPW	S		(403,880,531)	(231,959,087)	(434,116,327)	(245,185,593)
2361					B17	(403,880,531)	(231,959,087)	(434,116,327)	(245,185,593)
2362									
2363	108368	Line Transformers							
2364			DPW	S		(545,413,447)	(134,556,729)	(591,922,493)	(154,901,893)
2365					B17	(545,413,447)	(134,556,729)	(591,922,493)	(154,901,893)
2366									
2367	108369	Services							
2368			DPW	S		(326,302,278)	(111,082,559)	(354,148,230)	(123,263,640)
2369					B17	(326,302,278)	(111,082,559)	(354,148,230)	(123,263,640)
2370									
2371	108370	Meters							
2372			DPW	S		(79,103,554)	(45,132,469)	(86,954,790)	(48,566,955)
2373					B17	(79,103,554)	(45,132,469)	(86,954,790)	(48,566,955)
2374									
2375									
2376									
2377	108371	Installations on Customers' Premises							
2378			DPW	S		(7,268,643)	(3,373,353)	(7,560,800)	(3,501,156)
2379					B17	(7,268,643)	(3,373,353)	(7,560,800)	(3,501,156)
2380									
2381	108372	Leased Property							
2382			DPW	S		-	-	-	-
2383					B17	-	-	-	-
2384									
2385	108373	Street Lights							
2386			DPW	S		(31,646,082)	(12,413,319)	(33,724,974)	(13,322,721)
2387					B17	(31,646,082)	(12,413,319)	(33,724,974)	(13,322,721)

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2388									
2389	108D00	Unclassified Dist Plant - Acct 300							
2390			DPW	S		-	-	-	-
2391					B17	-	-	-	-
2392									
2393	108DS	Unclassified Dist Sub Plant - Acct 300							
2394			DPW	S		-	-	-	-
2395					B17	-	-	-	-
2396									
2397	108DP	Unclassified Dist Sub Plant - Acct 300							
2398			DPW	S		6,041,092	3,413,437	6,041,092	3,413,437
2399					B17	6,041,092	3,413,437	6,041,092	3,413,437
2400									
2401									
2402	**Total Distribution Plant Accum Depreciation**				**B17**	**(2,887,640,471)**	**(998,892,349)**	**(3,122,504,624)**	**(1,101,632,566)**
2403									
2404	Summary of Distribution Plant Depr by Factor								
2405		S				(2,887,640,471)	(998,892,349)	(3,122,504,624)	(1,101,632,566)
2406									
2407	Total Distribution Depreciation by Factor					(2,887,640,471)	(998,892,349)	(3,122,504,624)	(1,101,632,566)
2408	108GP	General Plant Accumulated Depr							
2409			G-SITUS	S		(247,853,687)	(85,203,161)	(272,298,066)	(95,657,209)
2410			G-DGP	SG		(864,020)	(380,147)	(733,304)	(322,636)
2411			G-DGU	SG		(2,957,865)	(1,301,386)	(3,023,369)	(1,330,207)
2412			G-SG	SG		(113,340,150)	(49,866,830)	(130,423,218)	(57,382,953)
2413			CUST	CN		(6,399,767)	(3,059,690)	(5,443,176)	(2,602,350)
2414			PTD	SO		(107,174,972)	(46,512,363)	(110,490,583)	(48,168,025)
2415			P	SE		(1,606,021)	(696,310)	(1,815,595)	(787,173)
2416			G-SG	SG		(110,882)	(48,785)	(132,826)	(58,440)
2417			G-SG	SG		(2,711,121)	(1,192,825)	(2,912,078)	(1,281,241)
2418					B17	(483,018,484)	(188,261,498)	(527,272,217)	(207,590,235)
2419									
2420									
2421	108MP	Mining Plant Accumulated Depr.							
2422			P	S		-	-	-	-
2423			P	SE		-	-	-	-
2424					B17	-	-	-	-
2425	108MP	Less Centralia Situs Depreciation							
2426			P	S		-	-	-	-
2427					B17	-	-	-	-
2428									
2429	1081390	Accum Depr - Capital Lease							
2430			PTD	SO	B17	-	-	-	-
2431						-	-	-	-
2432									
2433		Remove Capital Leases				-	-	-	-
2434					B17	-	-	-	-
2435									
2436	1081399	Accum Depr - Capital Lease							
2437			P	S		-	-	-	-
2438			P	SE	B17	-	-	-	-
2439						-	-	-	-
2440									
2441		Remove Capital Leases				-	-	-	-
2442					B17	-	-	-	-
2443									
2444									
2445	**Total General Plant Accum Depreciation**				**B17**	**(483,018,484)**	**(188,261,498)**	**(527,272,217)**	**(207,590,235)**
2446									
2447									
2448									
2449	Summary of General Depreciation by Factor								
2450		S				(247,853,687)	(85,203,161)	(272,298,066)	(95,657,209)
2451		DGP				-	-	-	-
2452		DGU				-	-	-	-
2453		SE				(1,606,021)	(696,310)	(1,815,595)	(787,173)
2454		SO				(107,174,972)	(46,512,363)	(110,490,583)	(48,168,025)
2455		CN				(6,399,767)	(3,059,690)	(5,443,176)	(2,602,350)
2456		SG				(119,984,038)	(52,789,975)	(137,224,796)	(60,375,477)
2457		DEU				-	-	-	-
2458		SSGCT				-	-	-	-
2459		SSGCH				-	-	-	-
2460		Remove Capital Leases				-	-	-	-
2461	Total General Depreciation by Factor					(483,018,484)	(188,261,498)	(527,272,217)	(207,590,235)
2462									
2463									
2464	**Total Accum Depreciation - Plant In Service**				**B17**	**(9,906,332,026)**	**(4,060,171,405)**	**(9,892,571,849)**	**(4,183,178,675)**

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2465	111SP	Accum Prov for Amort-Steam							
2466			P	SG		-	-	-	-
2467			P	SG		-	-	-	-
2468					B18	-	-	-	-
2469									
2470									
2471	111GP	Accum Prov for Amort-General							
2472			G-SITUS	S		(11,074,062)	(18,348)	(11,906,486)	(38,533)
2473			CUST	CN		-	-	-	-
2474			I-SG	SG		-	-	-	-
2475			PTD	SO		(3,442,703)	(1,494,083)	(4,011,409)	(1,748,761)
2476			P	SE		-	-	-	-
2477					B18	(14,516,766)	(1,512,431)	(15,917,895)	(1,787,294)
2478									
2479									
2480	111HP	Accum Prov for Amort-Hydro							
2481			P	SG		-	-	-	-
2482			P	SG		-	-	-	-
2483			P	SG		(2,515,843)	(1,106,908)	(3,139,235)	(1,381,185)
2484			P	SG		-	-	-	-
2485					B18	(2,515,843)	(1,106,908)	(3,139,235)	(1,381,185)
2486									
2487									
2488	111IP	Accum Prov for Amort-Intangible Plant							
2489			I-SITUS	S		29,187,452	30,385,088	(1,349,626)	(101,675)
2490			I-DGP	SG		-	-	-	-
2491			I-DGU	SG		(489,827)	(215,512)	(522,295)	(229,797)
2492			P	SE		-	-	1,106,269	479,636
2493			I-SG	SG		(89,975,106)	(39,586,795)	(97,237,053)	(42,781,871)
2494			I-SG	SG		(105,415,501)	(46,380,183)	(40,268,216)	(17,717,007)
2495			I-SG	SG		(6,044,246)	(2,659,317)	(6,647,361)	(2,924,673)
2496			CUST	CN		(137,086,578)	(65,540,264)	(159,953,717)	(76,472,905)
2497			P	SG		-	-	-	-
2498			P	SG		(21,945)	(9,655)	(26,408)	(11,619)
2499			PTD	SO		(291,767,035)	(126,622,606)	(305,462,840)	(133,165,573)
2500					B18	(601,612,785)	(250,629,245)	(610,361,247)	(272,925,483)
2501	111IP	Less Non-Regulated Plant							
2502			NUTIL	OTH		-	-	-	-
2503						(601,612,785)	(250,629,245)	(610,361,247)	(272,925,483)
2504									
2505	111390	Accum Amtr - Capital Lease							
2506			G-SITUS	S		-	-	-	-
2507			P	SG		-	-	-	-
2508			PTD	SO		-	-	-	-
2509					B9	-	-	-	-
2510									
2511		Remove Capital Lease Amtr				-	-	-	-
2512									
2513	**Total Accum Provision for Amortization**				**B18**	**(618,645,394)**	**(253,248,584)**	**(629,418,377)**	**(276,093,963)**
2514									
2515									
2516									
2517									
2518	Summary of Amortization by Factor								
2519		S				18,113,390	30,366,740	(13,256,111)	(140,208)
2520		DGP				-	-	-	-
2521		DGU				-	-	-	-
2522		SE				-	-	1,106,269	479,636
2523		SO				(295,209,738)	(128,116,689)	(309,474,250)	(134,914,335)
2524		CN				(137,086,578)	(65,540,264)	(159,953,717)	(76,472,905)
2525		SSGCT				-	-	-	-
2526		SSGCH				-	-	-	-
2527		SG				(204,462,468)	(89,958,371)	(147,840,568)	(65,046,151)
2528		Less Capital Lease				-	-	-	-
2529	Total Provision For Amortization by Factor					(618,645,394)	(253,248,584)	(629,418,377)	(276,093,963)

Rocky Mountain Power
Utah Rate Case, December 31, 2021 Test Period

Rebuttal Adjustment Summary

The following is a summary of the rebuttal adjustments included in the Company's revised revenue requirement addressing corrections identified by the Company and items raised in the direct testimony of intervening parties.

10.1 – Wheeling Revenue Update
This adjustment removes out-of-period and one-time adjustments from the 12 months ended December 2019 and adds in annualizing and pro forma changes through December 2021. This rebuttal adjustment was updated with a revised forecast which most notably includes an update to the OATT rate to incorporate the TCJA.

10.2 – REC Revenue Update
This incremental adjustment incorporates and accepts two changes to the total REC revenue amount as proposed by OCS. Specifically, these updates include an additional $24 thousand into the Test Year to account for the revised Kennecott REC Supply Agreement and the inclusion of the REC revenues associated with the Vitesse, LLC REC agreement.

10.3 – NTUA Revenue Correction
This incremental adjustment accepts the OCS's proposal to remove the UT situs revenues from the Test Period as referenced in data response OCS 5.23.

10.4 – M&S Inventory Sales Revenue Correction
This incremental adjustment accepts the OCS's proposal to re-allocate the sale of M&S inventory to offset the cost of inventory sales. Included in this adjustment is a true up for any timing differences between the sales and cost of goods sold. The M&S inventory sales (Sec. Acc 362950) and cost of sales (Sec. Acc 514950) should offset one another for net zero impact.

10.5 – Schedule 300 Fees
This incremental adjustment accepts the OCS's proposal to include all Schedule 300 fees. These fees are summarized in Exhibit RMP__(MSN_1), which was provided in the initial filing.

10.6 – Reliability Coordinator Fees
This adjustment adopts intervening parties' recommendation to adjust the test year reliability coordinator fees to levels more reflective of expenses that can be expected under the Company's current reliability coordinator. Please refer to the Company's response to UAE 2.44 for details on this issue.

10.7 – Transmission Power Delivery Uncollectible Expense
This adjustment replaces the Base Period Transmission PD uncollectible expenses with a three-year average.

10.8 – Insurance Premium Update
This incremental adjustment incorporates the most recent insurance premium renewal amounts which will be in place during the majority of the Test Year.

10.9 – Wildland Fire O&M Update
This incremental adjustment walks forward the 12 ME December 2019 base period level of operations and maintenance expense for the Wildland Fire mitigation ("House Bill 66") efforts to the pro forma 12 ME December 2021 amount. This adjustment is updated to the House Bill 66 filing, which was submitted after the initial filing of the general rate case.

10.10 – WEBA – Full-Time Equivalents
This adjustment accepts the proposed adjustment by UAE to reduce FTE's from the Base Period to the Test Year by 35.2.

10.11 – WEBA – UMWA Correction
This adjustment removes an amount associated with the UMWA retiree medical benefit obligations that was double-counted and also included in the Deer Creek Mine adjustment (Page 8.14) of the direct filing.

10.12 – WEBA – CY 2021 Annualization
This adjustment accepts UAE's proposal to remove the annualized level of increases associated with CY 2021.

10.13 – Rebuttal Net Power Cost Alignment
This adjustment is modified to reflect the updated in-service dates of the TB Flats and Pryor Mountain wind projects.

10.14 – Nodal Pricing Model Update
This adjustment adds the software related rate base and on-going O&M costs for the Nodal Pricing Model as agreed upon in the Multi-State Process filed in Docket No. 19-035-42, Appendix D. As part of the Company's response to UAE 3.9 1st REVISED the estimated in-service amount of this project increased from $4.0 million to $4.5 million. This incremental adjustment captures that change.

10.15 – Other Decommissioning Cost – Colstrip - Correction
This adjustment corrects the remaining life calculation for the Colstrip plant to the appropriate seven years.

10.16 – Electric Plant Acquisition Adjustment
This adjustment accepts the adjustment proposed by OCS that the Protected PP&E EDIT Amortization Regulatory Liability be used to buy-down the remaining unamortized balance of the Craig and Hayden electric plant acquisition adjustment.

10.17 – Property Tax Update
This incremental adjustment reflects the difference between the filed property taxes and the revised property taxes, which used the updated 2020 capitalization rates.

10.18 – Pro-Forma Tax
This adjustment normalizes base period schedule M, deferred tax expense, and accumulated deferred income tax balances to an estimated pro forma level for the CY December 2021 test period. The rebuttal filing includes an incremental change to reflect the impacts of a 481(a) adjustment related to bonus depreciation that was filed with the 2019 tax return. This adjustment also incorporates changes to PTCs as a result of the delayed in-service for Pryor Mountain and TB Flats.

10.19 – Removal of TCJA Deferred Balances - Correction
This incremental adjustment corrects the removal of the non-protected property EDIT regulatory liability.

10.20 – Pro-Forma Plant Data Update
This incremental adjustment incorporates updates to the Test Year capital additions proposed by Mr. Higgins as provided in the data request response UAE 3.9 1st Revised. The incremental change to Nodal Pricing is included in 10.14. The UT AMI project is removed as filed and updated with the current project costs. This adjustment also updates the new projects identified in UAE 3.9 1st Revised and other projects found during the preparation of the rebuttal filing. Also, this incremental adjustment captures the updated in-service dates for the new wind projects.

10.21 – Repowering Capital Additions
This adjustment adds the trailing capital additions for the repowering projects that were in-service in the Base Period.

10.22 – Pryor Mountain and TB Flats – Phase 2
This adjustment reflects the full first-year revenue requirement associated with the delayed portions of TB Flats and Pryor Mountain. Additional details on the delays on these projects are provided in the testimonies of Mr. Van Engelenhoven and Mr. Hemstreet.

Rocky Mountain Power
Utah General Rate Case - December 2021
Tab 10 Adjustment Summary

					10.1	10.2	10.3
	Total Adjustments	Capital Cost - Cost of Debt	Capital Cost - Cost of Equity	O&M Escalation Removal	Wheeling Revenue Update	REC Revenues Update	NTUA Revenue Correction
1 Operating Revenues:							
2 General Business Revenues	[redacted]	-	-	-	-	[redacted]	-
3 Interdepartmental	[redacted]	-	-	-	-	[redacted]	-
4 Special Sales	[redacted]	-	-	-	-	[redacted]	77,250
5 Other Operating Revenues	[redacted]	-	-	-	(2,255,628)	[redacted]	-
6 Total Operating Revenues	[redacted]	-	-	-	(2,255,628)	[redacted]	77,250
7							
8 Operating Expenses:	[redacted]					[redacted]	
9 Steam Production	[redacted]	-	-	(1,444,665)	-	[redacted]	-
10 Nuclear Production	[redacted]	-	-	-	-	[redacted]	-
11 Hydro Production	[redacted]	-	-	24,796	-	[redacted]	-
12 Other Power Supply	[redacted]	-	-	(176,336)	-	[redacted]	-
13 Transmission	[redacted]	-	-	(198,296)	-	[redacted]	-
14 Distribution	[redacted]	-	-	(259,538)	-	[redacted]	-
15 Customer Accounting	[redacted]	-	-	(435,483)	-	[redacted]	-
16 Customer Service & Info	[redacted]	-	-	(48,197)	-	[redacted]	-
17 Sales	[redacted]	-	-	-	-	[redacted]	-
18 Administrative & General	[redacted]	-	-	(1,004,849)	-	[redacted]	-
19							
20 Total O&M Expenses	[redacted]	-	-	(3,542,567)	-	[redacted]	-
21							
22 Depreciation	[redacted]	-	-	-	-	[redacted]	-
23 Amortization	[redacted]	-	-	-	-	[redacted]	-
24 Taxes Other Than Income	[redacted]	-	-	-	-	[redacted]	-
25 Income Taxes - Federal	[redacted]	144,687	-	710,296	(452,149)	[redacted]	15,485
26 Income Taxes - State	[redacted]	32,768	-	160,862	(102,399)	[redacted]	3,507
27 Income Taxes - Def Net	[redacted]	-	-	-	-	[redacted]	-
28 Investment Tax Credit Adj.	[redacted]	-	-	-	-	[redacted]	-
29 Misc Revenue & Expense	[redacted]	-	-	-	-	[redacted]	-
30							
31 Total Operating Expenses:	[redacted]	177,454	-	(2,671,408)	(554,548)	[redacted]	18,992
32							
33 Operating Rev For Return:	[redacted]	(177,454)	-	2,671,408	(1,701,079)	[redacted]	58,258
34							
35 Rate Base:	[redacted]					[redacted]	
36 Electric Plant In Service	[redacted]	-	-	-	-	[redacted]	-
37 Plant Held for Future Use	[redacted]	-	-	-	-	[redacted]	-
38 Misc Deferred Debits	[redacted]	-	-	-	-	[redacted]	-
39 Elec Plant Acq Adj	[redacted]	-	-	-	-	[redacted]	-
40 Nuclear Fuel	[redacted]	-	-	-	-	[redacted]	-
41 Prepayments	[redacted]	-	-	-	-	[redacted]	-
42 Fuel Stock	[redacted]	-	-	-	-	[redacted]	-
43 Material & Supplies	[redacted]	-	-	-	-	[redacted]	-
44 Working Capital	[redacted]	1,978	-	(29,776)	(6,181)	[redacted]	212
45 Weatherization Loans	[redacted]	-	-	-	-	[redacted]	-
46 Misc Rate Base	[redacted]	-	-	-	-	[redacted]	-
47							
48 Total Electric Plant:	[redacted]	1,978	-	(29,776)	(6,181)	[redacted]	212
49							
50 Rate Base Deductions:	[redacted]	-	-	-	-	[redacted]	-
51 Accum Prov For Deprec	[redacted]	-	-	-	-	[redacted]	-
52 Accum Prov For Amort	[redacted]	-	-	-	-	[redacted]	-
53 Accum Def Income Tax	[redacted]	-	-	105	-	[redacted]	-
54 Unamortized ITC	[redacted]	-	-	-	-	[redacted]	-
55 Customer Adv For Const	[redacted]	-	-	-	-	[redacted]	-
56 Customer Service Deposits	[redacted]	-	-	-	-	[redacted]	-
57 Misc Rate Base Deductions	[redacted]	-	-	-	-	[redacted]	-
58							
59 Total Rate Base Deductions	[redacted]	-	-	105	-	[redacted]	-
60							
61 Total Rate Base:	[redacted]	1,978	-	(29,671)	(6,181)	[redacted]	212
62							
63 Return on Rate Base	[redacted]	-0.002%	0.000%	0.034%	-0.022%	[redacted]	0.001%
64							
65 Return on Equity	[redacted]	0.013%	0.000%	0.064%	-0.041%	[redacted]	0.001%
66							
67 TAX CALCULATION:							
68 Operating Revenue	[redacted]	-	-	3,542,567	(2,255,628)	[redacted]	77,250
69 Other Deductions	[redacted]	-	-	-	-	[redacted]	-
70 Interest (AFUDC)	[redacted]	-	-	-	-	[redacted]	-
71 Interest	[redacted]	(721,751)	-	(658)	(137)	[redacted]	5
72 Schedule "M" Additions	[redacted]	-	-	(0)	-	[redacted]	-
73 Schedule "M" Deductions	[redacted]	-	-	-	-	[redacted]	-
74 Income Before Tax	[redacted]	721,751	-	3,543,225	(2,255,491)	[redacted]	77,245
75							
76 State Income Taxes	[redacted]	32,768	-	160,862	(102,399)	[redacted]	3,507
77 Taxable Income	[redacted]	688,984	-	3,382,363	(2,153,091)	[redacted]	73,738
78							
79 Federal Income Taxes + Other	[redacted]	144,687	-	710,296	(452,149)	[redacted]	15,485
APPROXIMATE PRICE CHANGE	[redacted]	(725,237)	(22,291,405)	(3,567,245)	2,266,267	[redacted]	(77,614)

Rocky Mountain Power
Utah General Rate Case - December 2021
Tab 10 Adjustment Summary

		10.4	10.5	10.6	10.7	10.8	10.9	10.10
		M&S Inventory Sales Revenue Correction	Schedule 300 Fees	Reliability Coordinator Fees	Transmission Power Delivery Uncollectible Expense	Insurance Premium Update	Wildland Fire O&M Update	WEBA - Full-Time Equivalent
1	Operating Revenues:							
2	General Business Revenues	-	-	-	-	-	-	-
3	Interdepartmental	-	-	-	-	-	-	-
4	Special Sales	-	-	-	-	-	-	-
5	Other Operating Revenues	2,820,864	746,073	-	-	-	-	-
6	Total Operating Revenues	2,820,864	746,073	-	-	-	-	-
7								
8	Operating Expenses:							
9	Steam Production	-	-	-	-	-	-	(338,855)
10	Nuclear Production	-	-	-	-	-	-	-
11	Hydro Production	-	-	-	-	-	-	(70,857)
12	Other Power Supply	-	-	-	-	-	-	(124,694)
13	Transmission	-	-	(1,352,321)	-	-	66,662	(100,072)
14	Distribution	-	-	-	-	-	1,431,508	(406,115)
15	Customer Accounting	-	-	-	(312,475)	-	-	(127,043)
16	Customer Service & Info	-	-	-	-	-	-	(27,453)
17	Sales	-	-	-	-	-	-	-
18	Administrative & General	-	-	-	-	1,751,124	-	(157,167)
19								
20	Total O&M Expenses	-	-	(1,352,321)	(312,475)	1,751,124	1,498,170	(1,352,257)
21								
22	Depreciation	-	-	-	-	-	-	-
23	Amortization	-	-	-	-	-	-	-
24	Taxes Other Than Income	-	-	-	-	-	-	-
25	Income Taxes - Federal	565,453	149,553	271,145	62,745	(351,106)	(300,388)	271,132
26	Income Taxes - State	128,059	33,870	61,407	14,210	(79,516)	(68,030)	61,404
27	Income Taxes - Def Net	-	-	-	0	-	-	-
28	Investment Tax Credit Adj.	-	-	-	-	-	-	-
29	Misc Revenue & Expense	-	-	-	-	-	-	-
30								
31	Total Operating Expenses:	693,512	183,423	(1,019,769)	(235,520)	1,320,502	1,129,752	(1,019,721)
32								
33	Operating Rev For Return:	2,127,351	562,650	1,019,769	235,520	(1,320,502)	(1,129,752)	1,019,721
34								
35	Rate Base:							
36	Electric Plant In Service	-	-	-	-	-	-	-
37	Plant Held for Future Use	-	-	-	-	-	-	-
38	Misc Deferred Debits	-	-	-	-	-	-	-
39	Elec Plant Acq Adj	-	-	-	-	-	-	-
40	Nuclear Fuel	-	-	-	-	-	-	-
41	Prepayments	-	-	-	-	-	-	-
42	Fuel Stock	-	-	-	-	-	-	-
43	Material & Supplies	-	-	-	-	-	-	-
44	Working Capital	7,730	2,044	(11,367)	(2,625)	14,719	12,593	(11,366)
45	Weatherization Loans	-	-	-	-	-	-	-
46	Misc Rate Base	-	-	-	-	-	-	-
47								
48	Total Electric Plant:	7,730	2,044	(11,367)	(2,625)	14,719	12,593	(11,366)
49								
50	Rate Base Deductions:	-	-	-	-	-	-	-
51	Accum Prov For Deprec	-	-	-	-	-	-	-
52	Accum Prov For Amort	-	-	-	-	-	-	-
53	Accum Def Income Tax	-	-	-	(20,931)	-	-	-
54	Unamortized ITC	-	-	-	-	-	-	-
55	Customer Adv For Const	-	-	-	-	-	-	-
56	Customer Service Deposits	-	-	-	-	-	-	-
57	Misc Rate Base Deductions	-	-	-	-	-	-	-
58								
59	Total Rate Base Deductions	-	-	-	(20,931)	-	-	-
60								
61	Total Rate Base:	7,730	2,044	(11,367)	(23,557)	14,719	12,593	(11,366)
62								
63	Return on Rate Base	0.027%	0.007%	0.013%	0.003%	-0.017%	-0.015%	0.013%
64								
65	Return on Equity	0.051%	0.013%	0.024%	0.006%	-0.032%	-0.027%	0.024%
66								
67	TAX CALCULATION:							
68	Operating Revenue	2,820,864	746,073	1,352,321	312,475	(1,751,124)	(1,498,170)	1,352,257
69	Other Deductions	-	-	-	-	-	-	-
70	Interest (AFUDC)	-	-	-	-	-	-	-
71	Interest	172	45	(252)	(523)	327	279	(252)
72	Schedule "M" Additions	-	-	-	0	-	-	-
73	Schedule "M" Deductions	-	-	-	-	-	-	-
74	Income Before Tax	2,820,692	746,028	1,352,573	312,998	(1,751,450)	(1,498,449)	1,352,509
75								
76	State Income Taxes	128,059	33,870	61,407	14,210	(79,516)	(68,030)	61,404
77	Taxable Income	2,692,633	712,158	1,291,167	298,788	(1,671,935)	(1,430,420)	1,291,105
78								
79	Federal Income Taxes + Other	565,453	149,553	271,145	62,745	(351,106)	(300,388)	271,132
	APPROXIMATE PRICE CHANGE	(2,834,169)	(749,592)	(1,360,092)	(316,205)	1,761,187	1,506,779	(1,360,027)

Rocky Mountain Power
Utah General Rate Case - December 2021
Tab 10 Adjustment Summary

	10.11	10.12	10.13	10.14	10.15	10.16	10.17
	WEBA - UMWA Correction	WEBA - CY 2021 Annualization	Rebuttal Net Power Cost Alignment	Nodal Pricing Model Update	Other Decommissioning Cost – Colstrip - Correction	Electric Plant Acquisition Adjustment	Property Tax Update
1 Operating Revenues:							
2 General Business Revenues	-	-	-	-	[redacted]	-	-
3 Interdepartmental	-	-	-	-	[redacted]	-	-
4 Special Sales	-	-	(138,782)	-	[redacted]	-	-
5 Other Operating Revenues	-	-	-	0	[redacted]	-	-
6 Total Operating Revenues	-	-	(138,782)	0	[redacted]	-	-
7							
8 Operating Expenses:					[redacted]		
9 Steam Production	(176,643)	(175,007)	3,281,701	-	[redacted]	-	-
10 Nuclear Production	-	-	-	-	[redacted]	-	-
11 Hydro Production	(36,938)	(36,596)	-	-	[redacted]	-	-
12 Other Power Supply	(65,002)	(64,400)	571,144	-	[redacted]	-	-
13 Transmission	(52,167)	(51,684)	(639,365)	-	[redacted]	-	-
14 Distribution	(211,705)	(209,745)	-	-	[redacted]	-	-
15 Customer Accounting	(66,227)	(65,614)	-	-	[redacted]	-	-
16 Customer Service & Info	(14,311)	(14,179)	-	-	[redacted]	-	-
17 Sales	-	-	-	-	[redacted]	-	-
18 Administrative & General	(81,931)	(81,172)	-	5	[redacted]	-	-
19							
20 Total O&M Expenses	(704,924)	(698,396)	3,213,480	5	[redacted]	-	-
21							
22 Depreciation	-	-	-	1	[redacted]	-	-
23 Amortization	-	-	-	7,446	[redacted]	(2,070,614)	-
24 Taxes Other Than Income	-	-	-	9	[redacted]	-	4,407,030
25 Income Taxes - Federal	141,340	140,031	(672,133)	(19,114)	[redacted]	11,787	(883,624)
26 Income Taxes - State	32,010	31,713	(152,220)	(4,329)	[redacted]	2,669	(200,116)
27 Income Taxes - Def Net	-	-	-	20,635	[redacted]	503,955	-
28 Investment Tax Credit Adj.	-	-	-	-	[redacted]	-	-
29 Misc Revenue & Expense	-	-	-	(0)	[redacted]	-	-
30							
31 Total Operating Expenses:	(531,575)	(526,652)	2,389,128	4,653	[redacted]	(1,552,203)	3,323,289
32							
33 Operating Rev For Return:	531,575	526,652	(2,527,909)	(4,653)	[redacted]	1,552,203	(3,323,289)
34							
35 Rate Base:					[redacted]		
36 Electric Plant In Service	-	-	-	205,604	[redacted]	-	-
37 Plant Held for Future Use	-	-	-	-	[redacted]	-	-
38 Misc Deferred Debits	-	-	-	17	[redacted]	-	-
39 Elec Plant Acq Adj	-	-	-	-	[redacted]	(1,708,124)	-
40 Nuclear Fuel	-	-	-	2	[redacted]	-	-
41 Prepayments	-	-	-	1	[redacted]	-	-
42 Fuel Stock	-	-	-	-	[redacted]	-	-
43 Material & Supplies	-	-	-	(0)	[redacted]	-	-
44 Working Capital	(5,925)	(5,870)	26,630	(260)	[redacted]	161	37,042
45 Weatherization Loans	-	-	-	(0)	[redacted]	-	-
46 Misc Rate Base	-	-	-	-	[redacted]	-	-
47							
48 Total Electric Plant:	(5,925)	(5,870)	26,630	205,364	[redacted]	(1,707,963)	37,042
49							
50 Rate Base Deductions:	-	-	-	-	[redacted]	-	-
51 Accum Prov For Deprec	-	-	-	(5)	[redacted]	-	-
52 Accum Prov For Amort	-	-	-	(4,047)	[redacted]	-	-
53 Accum Def Income Tax	-	-	-	(23,103)	[redacted]	-	-
54 Unamortized ITC	-	-	-	-	[redacted]	-	-
55 Customer Adv For Const	-	-	-	-	[redacted]	-	-
56 Customer Service Deposits	-	-	-	-	[redacted]	-	-
57 Misc Rate Base Deductions	-	-	-	(4)	[redacted]	-	-
58							
59 Total Rate Base Deductions	-	-	-	(27,160)	[redacted]	-	-
60							
61 Total Rate Base:	(5,925)	(5,870)	26,630	178,204	[redacted]	(1,707,963)	37,042
62							
63 Return on Rate Base	0.007%	0.007%	-0.032%	0.000%	[redacted]	0.021%	-0.043%
64							
65 Return on Equity	0.013%	0.013%	-0.060%	0.000%	[redacted]	0.040%	-0.080%
66							
67 TAX CALCULATION:							
68 Operating Revenue	704,924	698,396	(3,352,262)	(7,461)	[redacted]	2,070,614	(4,407,030)
69 Other Deductions	-	-	-	-	[redacted]	-	-
70 Interest (AFUDC)	-	-	-	3	[redacted]	-	-
71 Interest	(131)	(130)	591	3,954	[redacted]	(37,895)	822
72 Schedule "M" Additions	-	-	-	7,444	[redacted]	(2,049,712)	-
73 Schedule "M" Deductions	-	-	-	91,373	[redacted]	-	-
74 Income Before Tax	705,056	698,526	(3,352,853)	(95,348)	[redacted]	58,797	(4,407,852)
75							
76 State Income Taxes	32,010	31,713	(152,220)	(4,329)	[redacted]	2,669	(200,116)
77 Taxable Income	673,046	666,813	(3,200,633)	(91,019)	[redacted]	56,127	(4,207,735)
78							
79 Federal Income Taxes + Other	141,340	140,031	(672,133)	(19,114)	[redacted]	11,787	(883,624)
APPROXIMATE PRICE CHANGE	(708,975)	(702,409)	3,371,383	23,962	[redacted]	(2,238,716)	4,432,354

Rocky Mountain Power
Utah General Rate Case - December 2021
Tab 10 Adjustment Summary

	10.18	10.19	10.20	10.21	10.22
	Pro-Forma Tax Update	Removal of TCJA Deferred Balances - Correction	Pro-Forma Plant Data Update	Repowering Capital Additions	Pryor Mountain and TB Flats - Phase 2
1 Operating Revenues:					
2 General Business Revenues	-	-	-	-	-
3 Interdepartmental	-	-	-	-	-
4 Special Sales	-	-	-	-	-
5 Other Operating Revenues	-	-	(7,397)	6	336
6 Total Operating Revenues	-	-	(7,397)	6	336
7					
8 Operating Expenses:					
9 Steam Production	-	-	-	-	-
10 Nuclear Production	-	-	-	-	-
11 Hydro Production	-	-	-	-	-
12 Other Power Supply	-	-	(1,115,557)	-	1,115,557
13 Transmission	-	-	-	-	-
14 Distribution	-	-	(100,107)	-	-
15 Customer Accounting	-	-	-	-	-
16 Customer Service & Info	-	-	-	-	-
17 Sales	-	-	-	-	-
18 Administrative & General	-	-	(108,373)	83	4,920
19					
20 Total O&M Expenses	-	-	(1,324,038)	83	1,120,477
21					
22 Depreciation	-	-	(8,842,046)	127,716	7,615,263
23 Amortization	-	-	(167,513)	16	946
24 Taxes Other Than Income	-	-	(213,236)	164	9,680
25 Income Taxes - Federal	5,015,319	(15,871)	11,726,869	(179,516)	(8,875,805)
26 Income Taxes - State	1,069	(3,594)	2,655,811	(40,656)	(2,010,124)
27 Income Taxes - Def Net	-	-	(10,749,267)	175,887	7,989,874
28 Investment Tax Credit Adj.	-	-	-	-	-
29 Misc Revenue & Expense	-	-	4	(0)	(0)
30					
31 Total Operating Expenses:	5,016,388	(19,465)	(6,913,417)	83,695	5,850,310
32					
33 Operating Rev For Return:	(5,016,388)	19,465	6,906,020	(83,690)	(5,849,975)
34					
35 Rate Base:					
36 Electric Plant In Service	-	-	(220,929,555)	2,640,046	157,416,426
37 Plant Held for Future Use	-	-	-	-	-
38 Misc Deferred Debits	-	-	(377,612)	291	17,142
39 Elec Plant Acq Adj	-	-	-	-	-
40 Nuclear Fuel	-	-	(36,470)	28	1,656
41 Prepayments	-	-	(27,884)	21	1,266
42 Fuel Stock	-	-	-	-	-
43 Material & Supplies	-	-	4,524	(0)	(3)
44 Working Capital	55,914	(217)	109,600	(2,425)	(107,216)
45 Weatherization Loans	-	-	0	(0)	(0)
46 Misc Rate Base	-	-	-	-	-
47					
48 Total Electric Plant:	55,914	(217)	(221,257,398)	2,637,961	157,329,271
49					
50 Rate Base Deductions:	-	-	-	-	-
51 Accum Prov For Deprec	-	-	3,677,980	(118,312)	(4,129,709)
52 Accum Prov For Amort	-	-	415,058	(250)	(14,705)
53 Accum Def Income Tax	(1,117,501)	-	19,757,307	(170,530)	(5,263,173)
54 Unamortized ITC	-	-	-	-	-
55 Customer Adv For Const	-	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-
57 Misc Rate Base Deductions	-	3,568,513	94,367	(73)	(4,284)
58					
59 Total Rate Base Deductions	(1,117,501)	3,568,513	23,944,713	(289,163)	(9,411,871)
60					
61 Total Rate Base:	(1,061,587)	3,568,296	(197,312,685)	2,348,797	147,917,400
62					
63 Return on Rate Base	-0.063%	-0.003%	0.266%	-0.003%	-0.209%
64					
65 Return on Equity	-0.118%	-0.005%	0.495%	-0.006%	-0.389%
66					
67 TAX CALCULATION:					
68 Operating Revenue	-	-	10,539,433	(127,974)	(8,746,030)
69 Other Deductions	-	-	-	-	-
70 Interest (AFUDC)	-	-	64,237	26	1,582
71 Interest	(23,554)	79,171	(4,367,745)	52,118	3,282,133
72 Schedule "M" Additions	-	-	(10,080,016)	129,253	7,705,224
73 Schedule "M" Deductions	-	-	(53,735,105)	844,630	39,951,343
74 Income Before Tax	23,554	(79,171)	58,498,030	(895,496)	(44,275,864)
75					
76 State Income Taxes	1,069	(3,594)	2,655,811	(40,656)	(2,010,124)
77 Taxable Income	22,484	(75,576)	55,842,220	(854,840)	(42,265,740)
78					
79 Federal Income Taxes + Other	5,015,319	(15,871)	11,726,869	(179,516)	(8,875,805)
APPROXIMATE PRICE CHANGE	6,579,106	329,702	(28,868,638)	345,624	22,538,254

Rocky Mountain Power
Utah General Rate Case - December 2021
Wheeling Revenue Update

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED	REF#
Adjustment to Revenues:							
Other Electric Revenues	456	3	(5,126,718)	SG	43.997%	(2,255,628)	10.1.1

Description of Adjustment:

This adjustment removes out-of-period and one-time adjustments from the 12 months ended December 2019 and adds in annualizing and pro forma changes through December 2021. This rebuttal adjustment was updated with a revised forecast which most notably includes an update to the OATT rate to incorporate the TCJA.

Rocky Mountain Power
Utah General Rate Case - December 2021
Wheeling Revenue Update

	Account	Type	As Filed Total Company	Rebuttal Update Total Company	Adjustment	REF#
Adjustment to Revenues:						
Other Electric Revenues	456	1	(206,160)	(206,160)	-	10.1.2
Other Electric Revenues	456	2	388,791	388,791	-	10.1.2
Other Electric Revenues	456	3	8,322,931	3,196,213	(5,126,718)	10.1.2

Adjustment Detail:		
Actual Wheeling Revenues 12 ME December 2019	111,912,996	10.1.2
Total Adjustments	3,378,844	10.1.2
Adjusted Wheeling Revenues 12 ME December 2021	115,291,840	10.1.2

Rocky Mountain Power
Utah General Rate Case - December 2021
Wheeling Revenue Update

Customer	Total
3 Phases Renewables, Inc.	(3,352)
Arizona Public Service Company	(2,740)
Avangrid Renewables, LLC	(6,548,152)
Avista Corporation	(21,511)
BASIN ELECTRIC POWER COOPERATIVE	(1,055,407)
BLACK HILLS POWER & LIGHT COMPANY	(3,372,474)
BONNEVILLE POWER ADMINISTRATION	(17,530,141)
BONNEVILLE POWER ADMINISTRATION	(4,430,767)
Brookfield Energy Marketing L.P.	(277,876)
Calpine Energy Solutions, LLC	(1,276,994)
City of Roseville	(1,647,367)
Clatskanie PUD	(572,536)
Colorado Electric Utility Co.	(4,722)
Constellation NewEnergy, Inc.	(40,488)
CONSTELLATION POWER SOURCE, INC.	(1,908,294)
DESERET GENERATION & TRANS. CO-OP.	(5,115,075)
Eagle Energy Partners I LP	(20,281)
Energy Keepers, Inc.	(598)
Eugene Water & Electric Board	(119,851)
Evergreen BioPower	(383,676)
FALL RIVER RURAL ELECTRIC COOPERATI	(151,308)
Idaho Power Co. Balancing Ops	(868,374)
Intermountain Renewable(Cyrq Enrgy)	(415,716)
Los Angeles Dept. of Water & Power	(1,238,409)
Macquarie Energy LLC	(251,784)
MAG Energy Solutions Inc.	(111,916)
Moon Lake Electric Association	(19,262)
MORGAN STANLEY CAPITAL	(2,656,696)
Municipal Energy Agency of Nebraska	(1,013)
Navajo Tribal Utility Authority	(84,912)
NextEra Energy Resources, LLC	(3,381,068)
NV Energy	(209,197)
Obsidian Renewables, LLC	(29,634)
PACIFIC GAS & ELECTRIC COMPANY	(146,099)
PACIFICORP	(0)
PORTLAND GENERAL ELECTRIC COMPANY	(312,974)
POWEREX	(20,700,831)
RAINBOW ENERGY MARKETING CORPORATIO	(75,250)
Sacramento Municipal Utility Dist	(645,800)
Salt River Project	(859,917)
SeaWest Windpower, Inc.	(46,510)
Shell Energy NA (Coral Power)	(3,578,785)
SIERRA PACIFIC POWER COMPANY	(36,159)
So. Cal Public Power Authority	(32,287)
Southern California Edison Company	(3,786,149)
State of South Dakota	(136,719)
Tenaska Power Services Company	(386,839)
The Energy Authority	(113,043)
TRANSALTA ENERGY MARKETING CORP.	(408,484)
TRI-STATE GEN. & TRANS. ASSOCIATION	(602,368)
Tucson Electric Power Co.	(14,633)
U.S. Bureau of Reclamation	(52,702)
UTAH ASSOCIATED MUNICIPAL POWER SYS	(18,837,507)
UTAH MUNICIPAL POWER AGENCY	(3,027,703)
Warm Springs Power Enterprises	(119,700)
Westar Energy, Inc.	(2,703)
WESTERN AREA POWER ADMIN. - UT	(3,214,980)
WESTERN AREA POWER ADMINISTRATION	(62,744)
Cowlitz Revenue	(184,442)
Accruals and Adjustments	(776,077)
Total	**(111,912,996)**
	Ref 10.1.1

Type		
1	Remove refunds and other out of period adjustments	206,160
2	LH Garrett (Formerly Obsidian) 10MW	(388,791)
3	Airport Solar (Formerly Obsidian) 50MW	(2,092,203)
3	Falls Creek Hydro	(161,446)
3	BPA Lost Creek to Network	2,226,121
3	BPA Green Springs to Network	715,539
3	Forecasted Price/Volume Increase	(9,010,941)
3	Deferred Tax Rate Impact Adjustment	2,342,442
3	BPA Lost Creek to Network Deferred Tax Rate Adj	(64,755)
3	BPA Green Springs to Network Deferred Tax Rate Adj	(20,814)
3	Short Term Revenue Forecast Adjustment	2,869,845
	Incremental Adjustments	**(3,378,844)**
		Ref 10.1.1
	Accum Totals	**(115,291,840)**
		Ref 10.1.1

Rocky Mountain Power
Utah General Rate Case - December 2021
REC Revenue Update
REDACTED

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED	REF#
Adjustment to Revenue:							
2019 True-Up for Kennecott Contract	456	1	24,012	UT	Situs	24,012	10.2.1
Pryor Mountain Projected 2021 REC Revenues	456	3	[redacted]	SG	43.997%	[redacted]	10.2.1

Description of Adjustment:

This incremental adjustment incorporates and accepts two changes to the total REC revenue amount as proposed by OCS. Specifically, these updates include an additional $24 thousand into the Test Year to account for the revised Kennecott REC Supply Agreement and the inclusion of the REC revenues associated with the Vitesse, LLC REC agreement.

Rocky Mountain Power
Utah General Rate Case December 2021
REC Revenue Update
REDACTED

	Account	As Filed Total Company	Rebuttal Update Total Company	Adjustment	Ref
Adjustment to Revenue:					
Add December 2019 REC Revenues Reallocated According to RPS Eligibility:					
OR/CA/WA RPS Eligible:					
Reallocation of December 2019 Rev. for Non-RPS States	456	357,311	357,311	-	
Adjustment for CA RPS Banking	456	(14,288)	(14,288)	-	
Adjustment for OR RPS Banking	456	(260,664)	(260,664)	-	
Adjustment for WA RPS Banking	456	(82,359)	(82,359)	-	
		-	-	-	Adj. 3.2
OR/CA RPS Eligible					
Reallocation of December 2019 Rev. for Non-RPS States	456	1,476,746	1,476,746	-	
Adjustment for CA RPS Banking	456	(76,737)	(76,737)	-	
Adjustment for OR RPS Banking	456	(1,400,009)	(1,400,009)	-	
		-	-	-	Adj. 3.2
CA RPS Eligible					
Reallocation of December 2019 Rev. for Non-RPS States	456	3,623	3,623	-	
Adjustment for CA RPS Banking	456	(3,623)	(3,623)	-	
Adjustment for OR RPS - Ineligible Wind	456	(66,092)	(66,092)	-	
Adjustment for OR RPS - Ineligible Wind	456	66,092	66,092	-	
		-	-	-	Adj. 3.2
Remove REC Deferrals	456	1,132,426	1,132,426	-	Adj. 3.2
Retain 10 Percent Incentive on REC Revenue	456	(290,445)	(290,445)	-	Adj. 3.2
Kennecott Contract Situs Allocation	456	400,000	424,012	**24,012**	10.2.2
Kennecott Contract Administrative Fee	456	5,100	5,100	-	Adj. 3.2
Pryor Mountain Projected 2021 REC Revenues	456	-	[redacted]		10.2.2

Rocky Mountain Power
Utah General Rate Case December 2021
REC Revenue Update
Unadjusted Data
REDACTED

Posting Date	Fin Accrual	Fin Reversal	Back Office Actual	SAP Total	Kennecott Removal	SAP Total w/o Kennecott
FERC Acct (Ref B1)	4562700	4562700	4562700		4562700	
SAP Acct	301944	301944	301945		301945	
January-19	(109)	32,948	(192,815)	(159,976)		(159,976)
February-19	(919,873)	109	-	(919,764)		(919,764)
March-19	(278,133)	919,873	(1,078,766)	(437,026)		(437,026)
April-19	(296,559)	278,133	(277,994)	(296,419)		(296,419)
May-19	(262,337)	296,559	(296,200)	(261,978)	50,000	(211,978)
June-19	(323,878)	262,337	(261,134)	(322,675)	50,000	(272,675)
July-19	(50,617)	323,878	(323,300)	(50,039)	50,000	(39)
August-19	(50,623)	50,617	(50,000)	(50,007)	50,000	(7)
September-19	(404,074)	50,623	(50,000)	(403,451)	50,000	(353,451)
October-19	(971,769)	404,074	(147,000)	(714,695)	50,000	(664,695)
November-19	(847,638)	971,769	(971,010)	(846,878)	50,000	(796,878)
December-19	(870,212)	847,638	(760,214)	(782,789)	50,000	(732,789)
12 ME December 2019 Total	(5,275,823)	4,438,559	(4,408,432)	(5,245,697)	400,000	**(4,845,697)**
						Ref 3.2.2

REC deferrals included in unadjusted results:

FERC Account	4562700	
Amount Yr. Ended December 2019	**1,132,426**	**Ref 3.2**

10 Percent Incentive Details:

	Utah Allocated	Ref
Total Utah-allocated Base Year REC Revenues (Excl. LJ indemnity loss)	2,904,446	Ref. 3.2.2
Less: 10 Percent Incentive to be retained by the Company	**290,445**	**Ref. 3.2.2**
Base Year REC Revenues (Excluding LJ indemnity loss)	2,614,002	

Situs Allocation:

Kennecott Contract

Annual Kennecott REC Revenue per Contract	**600,000**	
FERC Account	4562700	
Kennecott Contract Amount Yr. Ended 2019	**400,000**	**Ref 3.2**

Kennecott Base Revenue

Amount Yr. Ended 2019 **175,988** **Ref 3.2**

Kennecott Administrative Fee

Administrative Fee 2021 **5,100** **Ref 3.2**

SG Allocation:

Projected Revenues 2021

Pyror Mountain Revenue Amount 2021 [redacted]

Rocky Mountain Power
Utah General Rate Case - December 2021
NTUA Revenue Correction

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED	REF#
Adjustment to Revenue:							
NTUA Revenue Correction	447	1	77,250	UT	Situs	77,250	10.3.1

Description of Adjustment:

This incremental adjustment accepts the OCS's proposal to remove the UT situs revenues from the Test Period as referenced in data response OCS 5.23.

Rocky Mountain Power
Utah General Rate Case - December 2021
NTUA Revenue Correction

	Account	As Filed Total Company	Rebuttal Update Total Company	Adjustment	Ref
NTUA Revenues	447	(13,606,145)	(13,606,145)	-	Adj. 3.5
NTUA Revenues	447	13,606,145	13,606,145	-	Adj. 3.5
NTUA Revenue Correction	447	-	77,250	77,250	10.3

Rocky Mountain Power
Utah General Rate Case - December 2021
M&S Inventory Sales Revenue Correction

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED	REF#
Adjustment to Revenue:							
M&S Inventory Sales	456	1	2,488,550	UT	Situs	2,488,550	10.4.1
M&S Inv. Cost and Sales True-Up	456	1	332,314	UT	Situs	332,314	10.4.1

Description of Adjustment:

This incremental adjustment accepts the OCS's proposal to re-allocate the sale of M&S inventory to offset the cost of inventory sales. Included in this adjustment is a true up for any timing differences between the sales and cost of goods sold. The M&S inventory sales (Sec. Acc 362950) and cost of sales (Sec. Acc 514950) should offset one another for net zero impact.

Rocky Mountain Power
Utah General Rate Case - December 2021
M&S Inventory Sales Revenue Correction

ADJUSTMENT DESCRIPTION	ACCOUNT	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED	Ref. #
Removing Incorrect FERC 456 Allocation SO	456	(4,419,730)	SO	43.695%	(1,931,180)	
Reallocating FERC 456 to Allocation UT	456	4,419,730	UT	100.000%	4,419,730	
Correct UT Allocation of Inventory Sales		-			2,488,550	10.4

ADJUSTMENT DESCRIPTION	SEC. ACCOUNT	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED	
M&S Inventory Sales	362950	(4,612,380)	UT	100.000%	(4,612,380)	
M&S Inventory Cost of Sales	514950	4,944,694	UT	100.000%	4,944,694	
True-Up Adjustment - Increase Revenue to Offset Expenses		332,314			332,314	10.4
				Adjustment Total	2,820,864	

B-Tab 1: Revenue
Electric Operations Revenue
Sum of Range: 01/2019 - 12/2019
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Utah
4562400	M&S INVENTORY SALES	362950	M&S INVENTORY SALES	OR	(0)	-
4562400	M&S INVENTORY SALES	362950	M&S INVENTORY SALES	SG	(1)	(0)
4562400	M&S INVENTORY SALES	362950	M&S INVENTORY SALES	SO	(4,420)	(1,931)
4562400	M&S INVENTORY SALES	362950	M&S INVENTORY SALES	UT	(193)	(193)
4562400 Total					(4,613)	(2,124)
4562500	M&S INV COST OF SALE	514950	M&S INVENTORY COST OF SALES	UT	4,945	4,945
4562500 Total					4,945	4,945

Note: Inventory sales and other revenue is recorded as a negative value on B Tab 1: Revenue; however, revenue is recorded as positive value for modeling.

Rocky Mountain Power
Utah General Rate Case - December 2021
Schedule 300 Fees

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED	REF#
Adjustment to Revenue:							
Misc. Electric Revenue	451	3	746,073	UT	Situs	746,073	10.5.1

Description of Adjustment:

This incremental adjustment accepts the OCS's proposal to include all Schedule 300 fees. These fees are summarized in Exhibit RMP__(MSN_1), which was provided in the initial filing.

Rocky Mountain Power
Utah General Rate Case - December 2021
Schedule 300 Fees

EXHIBIT RMP__(MSN-1) Schedule 300 Fee Summary

Rule	Charge	Situs UT: Times Charged 1/1/19-12/31/19	Current Charge	Proposed Charge	Incremental Change	
8R.2	Returned Payment Charge	27,164	$20	**$12**	(217,312)	
10R.9	Pole Cut Disconnect/Reconnect Charge: Normal Business Hours	19	$125	**$200**	1,425	
12R.11	Temp Service Charge - Single Phase	7,392	$85	**$215**	960,960	
12R.11	Temp Service Charge - Three Phase	10	$115	**$215**	1,000	
NEW	Paperless Bill Credit	0	$0	**$.50 Bill Credit**	NA	
					746,073	Ref. 10.5

Note: The Paperless Bill Credit is addressed in the Company's adjustment 4.8 - Paperless Bill Credits, which was provided in the initial filing.

Rocky Mountain Power
Utah General Rate Case - December 2021
Reliability Coordinator Fees

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED	REF#
Adjustment to Expense:							
Reliability Coordinator Fee	560	1	(3,073,632)	SG	43.997%	(1,352,321)	10.6.1

Description of Adjustment:

This adjustment adopts intervening parties' recommendation to adjust the test year reliability coordinator fees to levels more reflective of expenses that can be expected under the Company's current reliability coordinator. Please refer to the Company's response to UAE 2.44 for details on this issue.

Rocky Mountain Power
Utah General Rate Case - December 2021
Reliability Coordinator Fees

Base Period Expense[1]		Test Period Annual Expense
$5,059,884	CAISO 2020 RC Expense	$1,986,252
	Adjustment	**$ (3,073,632)**
		Ref 10.6

Notes:
1. 2020 service fees per Company's response to Data Request UAE 2.44.

Rocky Mountain Power
Utah General Rate Case - December 2021
Transmission Power Delivery Uncollectible Expense

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED	REF#
Adjustment to Expense:							
Adjust Trans. PD Uncoll. Exp	904	1	(653,585)	CN	47.809%	(312,475)	10.7.1

Description of Adjustment:

This adjustment replaces the Base Period Transmission PD uncollectible expenses with a three-year average.

Rocky Mountain Power
Utah General Rate Case - December 2021
Transmission Power Delivery Uncollectible Expense

550775 - Bad Debt Expense - Transmission PD	
2017	2,791
2018	298
2019	981,923
3-YR Average	328,337
Adjustment	(653,585)

Rocky Mountain Power
Utah General Rate Case - December 2021
Insurance Premium Update

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED	REF#
Adjustment to Expense:							
Adjust Liability Insurance Premium	925	3	3,928,723	SO	43.595%	1,712,714	10.8.1
Adjust Property Insurance Premium	924	3	78,928	SO	43.595%	34,409	10.8.1

Description of Adjustment:

This incremental adjustment incorporates the most recent insurance premium renewal amounts which will be in place during the majority of the Test Year. The new policy is effective August 15, 2020 to August 15, 2021.

Rocky Mountain Power
Utah General Rate Case - December 2021
Insurance Premium Update

	Account	As Filed Total Company	Rebuttal Update Total Company	Adjustment	Ref
Adjust Injuries & Damages Expense to 3-year Avg.	925	4,809,106	4,809,106	-	
Adjust property damage expense to 3-year average					
Property Insurance - Transmission	924	(52,891)	(52,891)	-	
Property Insurance - Utah Distribution	924	(739,470)	(739,470)	-	
Property Insurance - Non-T&D	924	(886,265)	(886,265)	-	
Adjust Liability Insurance Premium	925	2,137,838	6,066,561	3,928,723	10.8.2
Adjust Property Insurance Premium	924	(1,479,300)	(1,400,372)	78,928	10.8.2
Remove Injuries & Damages Reserve	2282	14,440,726	14,440,726	-	
Accumulated Deferred Income Tax Balance	190	(370,888)	(370,888)	-	

Rocky Mountain Power
Utah General Rate Case - December 2021
Insurance Premium Update
Adjust the Premium Renewal to Expected Test Period Level

	Premium Renewal Test Period	Included in Results 12 Months Ended Dec-19	Adjustment	Ref
Liability Insurance Premium	10,486,564	4,420,003	6,066,561	**10.8.1**
Property Insurance Premium	3,880,724	5,281,095	(1,400,372)	**10.8.1**
	14,367,287	**9,701,098**		
		Ref. 4.4.3		

Rocky Mountain Power
Utah General Rate Case - December 2021
Wildland Fire O&M Update

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED	REF#
Adjustment to Expense							
Distribution O&M Expense	580	3	1,431,508	UT	Situs	1,431,508	10.9.1
Transmission O&M Expense	560	3	151,513	SG	43.997%	66,662	10.9.1

Description of Adjustment:

This incremental adjustment walks forward the 12 ME December 2019 base period level of operations and maintenance expense for the Wildland Fire mitigation ("House Bill 66") efforts to the pro forma 12 ME December 2021 amount. This adjustment is updated to the House Bill 66 filing, which was submitted after the initial filing of the general rate case.

Rocky Mountain Power
Utah General Rate Case - December 2021
Wildland Fire O&M Update

	ACCOUNT	Type	FACTOR	AS-FILED TOTAL COMPANY	REBUTTAL TOTAL COMPANY	INCREMENTAL CHANGE TOTAL ALLOCATED	REF#
Adjustment to Expense							
Distribution O&M Expense	580	3	UT	(92,874)	1,338,634	1,431,508	10.9.2
Transmission O&M Expense	560	3	SG	(109,017)	42,496	151,513	10.9.2

Rocky Mountain Power
Utah General Rate Case - December 2021
Wildland Fire O&M Update

	Allocation	12 ME December 2019 Total Company	12 ME December 2021 Total Company	Adjustment Total Company	
Expenses					
Distribution					
Vegetation Inspections, Mitigation, Pole Clearing - Distribution	UT	1,860,000	1,320,000	(540,000)	
FHCA Inspections detail sound and bore; IR/Corona - Distribution	UT	622,000	765,000	143,000	
Condition Corrections - Distribution	UT	374,000	1,100,000	726,000	
Wood pole wrap - Distribution	UT	-	65,975	65,975	
Weather Station maint, tool development, Community Mtgs, Advertising - Other	UT	127,093	163,676	36,583	
Environmental - Wildlife protection program - Distribution	UT	-	433,476	433,476	
Fault Anticipator - Other	UT	-	105,000	105,000	
Patrolling costs, field response (PSPS) - Other	UT	81,400	200,000	118,600	
Alert Wildfire Cameras - other	UT	-	250,000	250,000	
Total Distribution O&M		3,064,493	4,403,127	**1,338,634**	**Ref. 10.9.1**
Transmission					
Vegetation Inspections, Mitigation, Pole Clearing - Transmission	SG	340,000	280,000	(60,000)	
FHCA Inspections - Transmission	SG	110,000	135,000	25,000	
Environmental - Wildlife protection program - Transmission	SG	-	76,496	76,496	
Condition Corrections - Transmission	SG	66,000	67,000	1,000	
Total Transmission O&M		516,000	558,496	**42,496**	**Ref. 10.9.1**
Total Expenses		**3,580,493**	**4,961,623**	**1,381,130**	

Rocky Mountain Power
Utah General Rate Case - December 2021
WEBA - Full-Time Equivalent

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED	REF#
Adjustment to Expense:							
Total O&M Expense Adjustment	500-935	3	(3,065,459)	Multiple	Multiple	(1,351,899)	10.10.1

Description of Adjustment:

This adjustment accepts the proposed adjustment by UAE to reduce FTE's from the Base Period to the Test Year by 35.2.

Rocky Mountain Power
Utah General Rate Case - December 2021
Wage and Employee Benefits - Full Time Equivalent
WEBA - Full Time Equivalent

Account	Description	Co. Rebuttal Filing Pro Forma after Adjustments 10.11 and 10.12 being applied 12 Months Ending December 2021	Co. Rebuttal Filing Pro Forma Line Item amounts being used for adjustment 10.10 FTE Adjustment	Incremental Adjustment	Ref
5001XX	Regular Ordinary Time	456,879,300	456,879,300	(3,266,735)	
5002XX	Overtime	69,138,674	-	-	
5003XX	Premium Pay	10,701,195	-	-	
	Subtotal for Escalation	**536,719,169**	**456,879,300**	**(3,266,735)**	
5005XX	Unused Leave Accrual	2,677,438	2,677,438	(19,144)	
500600	Temporary/Contract Labor	3,930	-	-	
500700	Severance Pay	(134,008)	-	-	
500850	Other Salary/Labor Costs	3,591,145	-	-	
50109X	Joint Owner Cutbacks	(1,272,245)	-	-	
	Subtotal Bare Labor	**541,585,429**	**459,556,738**	**(3,285,879)**	
500410	Annual Incentive Plan	29,777,703	29,777,703	(212,914)	
	Total Incentive	**29,777,703**	**29,777,703**	**(212,914)**	
500250	Overtime Meals	1,386,854	-	-	
500400	Bonus and Awards	1,776,665	1,776,665	(12,703)	
501325	Physical Exam	65,777	-	-	
502300	Education Assistance	133,630	-	-	
580899	Mining Salary/Benefit Credit	(192,027)	-	-	
	Total Other Labor	**3,170,899**	**1,776,665**	**(12,703)**	
	Subtotal Labor and Incentive	**574,534,031**	**491,111,106**	**(3,511,496)**	
50110X	Pensions	14,454,430	-	-	
501115	SERP Plan	2,779,392	-	-	
50115X	Post Retirement Benefits	1,321,376	-	-	
501160	Post Employment Benefits	6,323,807	6,323,807	(45,216)	
	Total Pensions	**24,879,004**	**6,323,807**	**(45,216)**	
501102	Pension Administration	617,162	-	-	
50112X	Medical	60,058,773	60,058,773	(429,427)	
50117X	Dental	4,256,813	4,256,813	(30,437)	
50120X	Vision	524,792	524,792	(3,752)	
50122X	Life	820,391	820,391	(5,866)	
50125X	401(k)	40,913,457	40,913,457	(292,536)	
501251	401(k) Administration	814	-	-	
501275	Accidental Death & Disability	37,225	-	-	
501300	Long-Term Disability	4,105,601	-	-	
5016XX	Worker's Compensation	1,524,505	1,524,505	(10,900)	
502900	Other Salary Overhead	1,291,410	-	-	
	Total Benefits	**114,150,943**	**108,098,732**	**(772,917)**	
	Subtotal Pensions and Benefits	**139,029,948**	**114,422,538**	**(818,133)**	
580XXX	Payroll Tax Expense	39,930,393	39,681,627	(248,766)	10.10.2
580700	Payroll Tax Expense-Unemployment	2,899,123	2,899,123	(20,729)	
	Total Payroll Taxes	**42,829,517**	**42,580,751**	**(269,495)**	
Total Labor		**756,393,495**	**648,114,395**	**(4,599,124)**	
Non-Utility and Capitalized Labor		252,233,862	216,126,127	(1,533,666)	
Total Utility Labor		**504,159,634**	**431,988,268**	**(3,065,459)**	Below
		Ref 10.10.6		**Ref 10.10.1**	

13 Avg FTE's as of - May 2020	4,892.1	10.10.3
13 Avg FTE's in Base Period - December 2019	4,927.3	10.10.3
Net FTE Reduction #	**(35.2)**	10.10.3
Net FTE Reduction %	**0.715%**	10.10.3

Rocky Mountain Power
Utah General Rate Case - December 2021
Wage and Employee Benefits - Full Time Equivalent
Payroll Tax Adjustment Calculation
WEBA - Full Time Equivalent

FICA Calculated on December 2021 Pro Forma Labor			**Social Security (SS)**	**Medicare**	**Total**	
Pro Forma Wages Adjustment	h		(3,266,735)	(3,266,735)		10.10.1
Pro Forma Incentive Adjustment	i		(212,914)	(212,914)		10.10.1
	j	h + i	(3,479,649)	(3,479,649)		
Percentage of SS eligible wages	k		91.92%	100.00%		
Total eligible wages	l	j * k	(3,198,567)	(3,479,649)		
Tax rate	m		6.20%	1.45%		
Tax on eligible wages	n	l * m	(198,311)	(50,455)		
Total FICA Tax - Incremental		n	(198,311)	(50,455)	(248,766)	10.10.1

Rocky Mountain Power
Utah General Rate Case - December 2021
Wage and Employee Benefits - Full Time Equivalent
Payroll Tax Adjustment Calculation
WEBA - Full Time Equivalent

Month	FTE - Actual			Ref
Jun-2018	5,039.5			
Jul-2018	5,047.5			
Aug-2018	5,017.5			
Sep-2018	5,000.0			
Oct-2018	5,023.5			
Nov-2018	5,004.5			
Dec-2018	4,988.0			
Jan-2019	4,994.5			
Feb-2019	4,999.5			
Mar-2019	4,963.5			
Apr-2019	4,964.0			
May-2019	4,936.5			
Jun-2019	4,919.5			
Jul-2019	4,886.0			
Aug-2019	4,868.0			
Sep-2019	4,866.0			
Oct-2019	4,872.5			
Nov-2019	4,905.5			
Dec-2019	4,891.5	4,927.3	<----- Ave 13 ME December 2019	10.10.1
Jan-2020	4,895.0			
Feb-2020	4,884.5			
Mar-2020	4,889.5			
Apr-2020	4,896.0			
May-2020	4,886.5	4,892.1	<----- Ave 13 ME May 2020	10.10.1
		(35.23)	**Reduction #**	10.10.1
		0.72%	**Reduction %**	10.10.1

Rocky Mountain Power
Utah General Rate Case - December 2021
Wage and Employee Benefits - Full Time Equivalent
2020 Protocol FERC Spread
WEBA - Full Time Equivalent

2020P Indicator	Rebuttal Pro Forma 12 Months Ending December 2021	% Of Total	Rebuttal Pro Forma Adjustment	Rebuttal Pro Forma 12 Months Ending December 2021	Utah Allocation %	Incremental Pro Forma Adjustment Utah Allocated	Incremental Pro Forma 12 Months Ending December 2021 Utah Allocated
500SG	14,331,560	1.895%	(87,141)	14,244,419	43.997%	(38,340)	6,267,188
502SG	21,042,448	2.782%	(127,945)	20,914,503	43.997%	(56,293)	9,201,858
503SE	124,239	0.016%	(755)	123,484	43.356%	(328)	53,538
505SG	957	0.000%	(6)	951	43.997%	(3)	419
506SG	34,647,159	4.581%	(210,666)	34,436,493	43.997%	(92,688)	15,151,195
510SG	3,631,498	0.480%	(22,081)	3,609,417	43.997%	(9,715)	1,588,053
511SG	8,796,616	1.163%	(53,486)	8,743,130	43.997%	(23,533)	3,846,758
512SG	28,291,843	3.740%	(172,024)	28,119,819	43.997%	(75,686)	12,372,017
513SG	13,101,172	1.732%	(79,659)	13,021,512	43.997%	(35,048)	5,729,140
514SG	2,699,771	0.357%	(16,416)	2,683,355	43.997%	(7,222)	1,180,609
535SG-P	5,735,986	0.758%	(34,877)	5,701,109	43.997%	(15,345)	2,508,345
535SG-U	3,712,618	0.491%	(22,574)	3,690,044	43.997%	(9,932)	1,623,527
536SG-P	29,605	0.004%	(180)	29,425	43.997%	(79)	12,946
537SG-P	590,093	0.078%	(3,588)	586,505	43.997%	(1,579)	258,048
537SG-U	29,309	0.004%	(178)	29,131	43.997%	(78)	12,817
539SG-P	7,295,838	0.965%	(44,361)	7,251,477	43.997%	(19,518)	3,190,468
539SG-U	5,839,586	0.772%	(35,507)	5,804,079	43.997%	(15,622)	2,553,650
540SG-P	223	0.000%	(1)	222	43.997%	(1)	98
541SG-P	-	0.000%	-	-	43.997%	-	-
542SG-P	263,729	0.035%	(1,604)	262,126	43.997%	(706)	115,329
542SG-U	11,825	0.002%	(72)	11,753	43.997%	(32)	5,171
543SG-P	425,705	0.056%	(2,588)	423,116	43.997%	(1,139)	186,161
543SG-U	341,632	0.045%	(2,077)	339,555	43.997%	(914)	149,396
544SG-P	994,873	0.132%	(6,049)	988,824	43.997%	(2,661)	435,058
544SG-U	230,179	0.030%	(1,400)	228,779	43.997%	(616)	100,657
545SG-P	889,588	0.118%	(5,409)	884,179	43.997%	(2,380)	389,016
545SG-U	96,048	0.013%	(584)	95,464	43.997%	(257)	42,002
546SG	4,545	0.001%	(28)	4,517	43.997%	(12)	1,988
548SG	6,431,018	0.850%	(39,103)	6,391,915	43.997%	(17,204)	2,812,283
549OR	39,486	0.005%	(240)	39,245	0.000%	-	-
549SG	4,583,512	0.606%	(27,869)	4,555,642	43.997%	(12,262)	2,004,369
552SG	931,549	0.123%	(5,664)	925,885	43.997%	(2,492)	407,366
553SG	1,872,339	0.248%	(11,384)	1,860,955	43.997%	(5,009)	818,774
554SG	94,863	0.013%	(577)	94,286	43.997%	(254)	41,483
556SG	492,797	0.065%	(2,996)	489,801	43.997%	(1,318)	215,500
557ID	49,877	0.007%	(303)	49,573	0.000%	-	-
557SG	32,200,573	4.257%	(195,790)	32,004,783	43.997%	(86,143)	14,081,304
560SG	7,369,323	0.974%	(44,808)	7,324,515	43.997%	(19,714)	3,222,603
561SG	10,970,665	1.450%	(66,705)	10,903,960	43.997%	(29,349)	4,797,470
562SG	2,101,783	0.278%	(12,780)	2,089,004	43.997%	(5,623)	919,109
563SG	554,820	0.073%	(3,373)	551,446	43.997%	(1,484)	242,622
566SG	50,953	0.007%	(310)	50,643	43.997%	(136)	22,282
567SG	180,799	0.024%	(1,099)	179,700	43.997%	(484)	79,063
568SG	1,152,523	0.152%	(7,008)	1,145,515	43.997%	(3,083)	503,998
569SG	3,391,957	0.448%	(20,624)	3,371,332	43.997%	(9,074)	1,483,302
570SG	7,696,576	1.018%	(46,798)	7,649,779	43.997%	(20,590)	3,365,711
571SG	3,909,113	0.517%	(23,769)	3,885,344	43.997%	(10,458)	1,709,454
572SG	28,839	0.004%	(175)	28,663	43.997%	(77)	12,611
580ID	(12,503)	-0.002%	76	(12,427)	0.000%	-	-
580OR	304,109	0.040%	(1,849)	302,260	0.000%	-	-
580SNPD	8,254,687	1.091%	(50,191)	8,204,496	48.488%	(24,337)	3,978,197
580UT	367,772	0.049%	(2,236)	365,536	100.000%	(2,236)	365,536
580WA	79,161	0.010%	(481)	78,680	0.000%	-	-
580WYP	113,514	0.015%	(690)	112,824	0.000%	-	-
581SNPD	13,274,745	1.755%	(80,715)	13,194,031	48.488%	(39,137)	6,397,523
582CA	32,809	0.004%	(199)	32,610	0.000%	-	-
582ID	279,278	0.037%	(1,698)	277,580	0.000%	-	-
582OR	261,386	0.035%	(1,589)	259,797	0.000%	-	-
582SNPD	2,608	0.000%	(16)	2,592	48.488%	(8)	1,257
582UT	1,151,164	0.152%	(6,999)	1,144,165	100.000%	(6,999)	1,144,165
582WA	110,646	0.015%	(673)	109,973	0.000%	-	-
582WYP	528,163	0.070%	(3,211)	524,952	0.000%	-	-
583CA	436,086	0.058%	(2,652)	433,434	0.000%	-	-
583ID	260,432	0.034%	(1,584)	258,848	0.000%	-	-
583OR	1,407,930	0.186%	(8,561)	1,399,369	0.000%	-	-
583SNPD	174	0.000%	(1)	173	48.488%	(1)	84
583UT	4,908,238	0.649%	(29,844)	4,878,394	100.000%	(29,844)	4,878,394
583WA	211,805	0.028%	(1,288)	210,517	0.000%	-	-
583WYP	370,074	0.049%	(2,250)	367,824	0.000%	-	-
583WYU	126,069	0.017%	(767)	125,303	0.000%	-	-
585SNPD	226,901	0.030%	(1,380)	225,521	48.488%	(669)	109,351
586CA	68,332	0.009%	(415)	67,917	0.000%	-	-
586ID	159,571	0.021%	(970)	158,601	0.000%	-	-
586OR	541,599	0.072%	(3,293)	538,306	0.000%	-	-
586UT	702,507	0.093%	(4,271)	698,236	100.000%	(4,271)	698,236

Utah General Rate Case - December 2021
Wage and Employee Benefits - Full Time Equivalent
2020 Protocol FERC Spread
WEBA - Full Time Equivalent

2020P Indicator	Rebuttal Pro Forma 12 Months Ending December 2021	% Of Total	Rebuttal Pro Forma Adjustment	Rebuttal Pro Forma 12 Months Ending December 2021	Utah Allocation %	Incremental Pro Forma Adjustment Utah Allocated	Incremental Pro Forma 12 Months Ending December 2021 Utah Allocated
586WA	265,433	0.035%	(1,614)	263,819	0.000%	-	-
586WYP	320,156	0.042%	(1,947)	318,210	0.000%	-	-
586WYU	87,823	0.012%	(534)	87,289	0.000%	-	-
587CA	504,377	0.067%	(3,067)	501,310	0.000%	-	-
587ID	754,303	0.100%	(4,586)	749,716	0.000%	-	-
587OR	4,801,150	0.635%	(29,193)	4,771,957	0.000%	-	-
587UT	4,528,095	0.599%	(27,532)	4,500,563	100.000%	(27,532)	4,500,563
587WA	977,915	0.129%	(5,946)	971,969	0.000%	-	-
587WYP	899,085	0.119%	(5,467)	893,619	0.000%	-	-
587WYU	88,278	0.012%	(537)	87,741	0.000%	-	-
588CA	48,077	0.006%	(292)	47,785	0.000%	-	-
588ID	(1,626)	0.000%	10	(1,616)	0.000%	-	-
588OR	13,386	0.002%	(81)	13,305	0.000%	-	-
588SNPD	3,411,475	0.451%	(20,743)	3,390,732	48.488%	(10,058)	1,644,099
588UT	(72,990)	-0.010%	444	(72,546)	100.000%	444	(72,546)
588WA	(717)	0.000%	4	(713)	0.000%	-	-
588WYP	9,910	0.001%	(60)	9,849	0.000%	-	-
588WYU	(50,928)	-0.007%	310	(50,618)	0.000%	-	-
589CA	15,253	0.002%	(93)	15,160	0.000%	-	-
589ID	10,935	0.001%	(66)	10,868	0.000%	-	-
589OR	74,402	0.010%	(452)	73,949	0.000%	-	-
589UT	313,531	0.041%	(1,906)	311,625	100.000%	(1,906)	311,625
589WA	12,531	0.002%	(76)	12,455	0.000%	-	-
589WYP	113,329	0.015%	(689)	112,640	0.000%	-	-
589WYU	6,917	0.001%	(42)	6,875	0.000%	-	-
590CA	106,108	0.014%	(645)	105,463	0.000%	-	-
590ID	173,594	0.023%	(1,056)	172,539	0.000%	-	-
590OR	839,275	0.111%	(5,103)	834,172	0.000%	-	-
590SNPD	2,747,157	0.363%	(16,704)	2,730,453	48.488%	(8,099)	1,323,942
590UT	1,378,062	0.182%	(8,379)	1,369,683	100.000%	(8,379)	1,369,683
590WA	171,852	0.023%	(1,045)	170,807	0.000%	-	-
590WYP	490,298	0.065%	(2,981)	487,317	0.000%	-	-
592CA	228,025	0.030%	(1,386)	226,639	0.000%	-	-
592ID	323,623	0.043%	(1,968)	321,656	0.000%	-	-
592OR	2,134,388	0.282%	(12,978)	2,121,411	0.000%	-	-
592SNPD	1,739,130	0.230%	(10,574)	1,728,556	48.488%	(5,127)	838,142
592UT	2,361,952	0.312%	(14,361)	2,347,591	100.000%	(14,361)	2,347,591
592WA	356,525	0.047%	(2,168)	354,357	0.000%	-	-
592WYP	775,168	0.102%	(4,713)	770,455	0.000%	-	-
592WYU	31,815	0.004%	(193)	31,622	0.000%	-	-
593CA	4,292,645	0.568%	(26,101)	4,266,545	0.000%	-	-
593ID	3,970,125	0.525%	(24,140)	3,945,986	0.000%	-	-
593OR	22,665,395	2.997%	(137,813)	22,527,582	0.000%	-	-
593SNPD	1,233,255	0.163%	(7,499)	1,225,756	48.488%	(3,636)	594,345
593UT	27,008,690	3.571%	(164,222)	26,844,468	100.000%	(164,222)	26,844,468
593WA	3,969,066	0.525%	(24,133)	3,944,932	0.000%	-	-
593WYP	3,831,594	0.507%	(23,297)	3,808,296	0.000%	-	-
593WYU	716,519	0.095%	(4,357)	712,162	0.000%	-	-
594CA	473,582	0.063%	(2,880)	470,703	0.000%	-	-
594ID	459,570	0.061%	(2,794)	456,776	0.000%	-	-
594OR	3,891,342	0.514%	(23,661)	3,867,681	0.000%	-	-
594SNPD	7,400	0.001%	(45)	7,355	48.488%	(22)	3,566
594UT	7,619,641	1.007%	(46,330)	7,573,311	100.000%	(46,330)	7,573,311
594WA	764,796	0.101%	(4,650)	760,145	0.000%	-	-
594WYP	722,141	0.095%	(4,391)	717,750	0.000%	-	-
594WYU	130,987	0.017%	(796)	130,190	0.000%	-	-
595SNPD	916,449	0.121%	(5,572)	910,877	48.488%	(2,702)	441,666
596CA	59,394	0.008%	(361)	59,033	0.000%	-	-
596ID	75,060	0.010%	(456)	74,604	0.000%	-	-
596OR	670,396	0.089%	(4,076)	666,320	0.000%	-	-
596UT	207,601	0.027%	(1,262)	206,339	100.000%	(1,262)	206,339
596WA	67,576	0.009%	(411)	67,165	0.000%	-	-
596WYP	253,914	0.034%	(1,544)	252,370	0.000%	-	-
596WYU	48,754	0.006%	(296)	48,458	0.000%	-	-
597CA	14,400	0.002%	(88)	14,313	0.000%	-	-
597ID	35,930	0.005%	(218)	35,711	0.000%	-	-
597OR	202,295	0.027%	(1,230)	201,065	0.000%	-	-
597SNPD	(120,959)	-0.016%	735	(120,223)	48.488%	357	(58,294)
597UT	196,028	0.026%	(1,192)	194,836	100.000%	(1,192)	194,836
597WA	13,947	0.002%	(85)	13,863	0.000%	-	-
597WYP	32,182	0.004%	(196)	31,986	0.000%	-	-
597WYU	16,518	0.002%	(100)	16,418	0.000%	-	-
598CA	7,147	0.001%	(43)	7,103	0.000%	-	-
598OR	48,139	0.006%	(293)	47,846	0.000%	-	-
598SNPD	1,554,817	0.206%	(9,454)	1,545,363	48.488%	(4,584)	749,316
598WA	14,354	0.002%	(87)	14,267	0.000%	-	-

Utah General Rate Case - December 2021
Wage and Employee Benefits - Full Time Equivalent
2020 Protocol FERC Spread
WEBA - Full Time Equivalent

2020P Indicator	Rebuttal Pro Forma 12 Months Ending December 2021	% Of Total	Rebuttal Pro Forma Adjustment	Rebuttal Pro Forma 12 Months Ending December 2021	Utah Allocation %	Incremental Pro Forma Adjustment Utah Allocated	Incremental Pro Forma 12 Months Ending December 2021 Utah Allocated
901CN	1,877,545	0.248%	(11,416)	1,866,129	47.809%	(5,458)	892,185
902CA	318,370	0.042%	(1,936)	316,434	0.000%	-	-
902CN	491,882	0.065%	(2,991)	488,891	47.809%	(1,430)	233,736
902ID	1,838,397	0.243%	(11,178)	1,827,219	0.000%	-	-
902OR	3,406,440	0.450%	(20,712)	3,385,727	0.000%	-	-
902UT	3,911,151	0.517%	(23,781)	3,887,370	100.000%	(23,781)	3,887,370
902WA	515,500	0.068%	(3,134)	512,366	0.000%	-	-
902WYP	892,978	0.118%	(5,430)	887,549	0.000%	-	-
902WYU	182,677	0.024%	(1,111)	181,567	0.000%	-	-
903CA	71,511	0.009%	(435)	71,076	0.000%	-	-
903CN	28,151,089	3.722%	(171,168)	27,979,921	47.809%	(81,834)	13,377,031
903ID	180,959	0.024%	(1,100)	179,859	0.000%	-	-
903OR	773,393	0.102%	(4,702)	768,690	0.000%	-	-
903UT	2,391,299	0.316%	(14,540)	2,376,759	100.000%	(14,540)	2,376,759
903WA	374,511	0.050%	(2,277)	372,234	0.000%	-	-
903WYP	422,067	0.056%	(2,566)	419,500	0.000%	-	-
903WYU	75,324	0.010%	(458)	74,866	0.000%	-	-
907CN	(9,523)	-0.001%	58	(9,465)	47.809%	28	(4,525)
908CA	2,845	0.000%	(17)	2,828	0.000%	-	-
908CN	2,300,783	0.304%	(13,990)	2,286,793	47.809%	(6,688)	1,093,302
908ID	(3)	0.000%	0	(3)	0.000%	-	-
908OR	2,253,495	0.298%	(13,702)	2,239,793	0.000%	-	-
908OTHER	61,298	0.008%	(373)	60,925	0.000%	-	-
908UT	2,653,362	0.351%	(16,133)	2,637,229	100.000%	(16,133)	2,637,229
908WA	376,318	0.050%	(2,288)	374,030	0.000%	-	-
908WYP	954,478	0.126%	(5,804)	948,674	0.000%	-	-
909CN	1,602,453	0.212%	(9,743)	1,592,710	47.809%	(4,658)	761,465
910CN	353	0.000%	(2)	351	47.809%	(1)	168
920OR	0.50	0.000%	(0.00)	0.50	0.000%	-	-
920SO	82,021,438	10.844%	(498,718)	81,522,720	43.595%	(217,414)	35,539,576
921SO	2,523,802	0.334%	(15,346)	2,508,457	43.595%	(6,690)	1,093,554
922SO	(24,764,598)	-3.274%	150,577	(24,614,021)	43.595%	65,644	(10,730,406)
925SO	-	0.000%	-	-	43.595%	-	-
928CA	24,090	0.003%	(146)	23,944	0.000%	-	-
928ID	36,958	0.005%	(225)	36,734	0.000%	-	-
928OR	143,785	0.019%	(874)	142,911	0.000%	-	-
928SO	507,691	0.067%	(3,087)	504,604	43.595%	(1,346)	219,980
928UT	100,238	0.013%	(609)	99,628	100.000%	(609)	99,628
928WA	266,437	0.035%	(1,620)	264,817	0.000%	-	-
928WYP	86,278	0.011%	(525)	85,753	0.000%	-	-
929SO	(3,584,079)	-0.474%	21,792	(3,562,287)	43.595%	9,500	(1,552,968)
935CA	1,277	0.000%	(8)	1,270	0.000%	-	-
935ID	1,690	0.000%	(10)	1,679	0.000%	-	-
935OR	12,572	0.002%	(76)	12,496	0.000%	-	-
935SO	2,223,598	0.294%	(13,520)	2,210,078	43.595%	(5,894)	963,476
935WA	298	0.000%	(2)	296	0.000%	-	-
935WYP	173	0.000%	(1)	172	0.000%	-	-
Utility Labor	**504,159,634**	**66.65309%**	**(3,065,459)**	**501,094,175**		**(1,351,899)**	**220,987,711**
						Ref 10.10	
Capital/Non Utility	252,233,862	33.34691%	(1,533,666)	250,700,196			
Total Labor	**756,393,495**	**100.00%**	**(4,599,124)**	**751,794,371**			
	Ref 10.10		Ref 10.10				

Rocky Mountain Power
Utah General Rate Case - December 2021
WEBA – UMWA Correction

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED	REF#
Adjustment to Expense:							
Post-retirement_ Remove UMWA Transfer	Various	3	(1,598,007)	Various	Various	(704,738)	10.11.11

Description of Adjustment:

This adjustment removes an amount associated with the UMWA retiree medical benefit obligations that was double-counted and also included in the Deer Creek Mine adjustment (Page 8.14) of the direct filing.

Rocky Mountain Power
Utah General Rate Case - December 2021
WEBA – UMWA Correction

The unadjusted, annualized (12 months ended December 2019), and pro forma period (12 months ending December 2021) labor expenses are summarized on page 10.11.2. The following is an explanation of the procedures used to develop the labor benefits & expenses used in this adjustment.

1. Actual December 2019 total labor related expenses are identified on page 10.11.2, including bare labor, incentive, other labor, pensions, benefits, and payroll taxes.

2. Actual December 2019 expenses for regular time, overtime, and premium pay were identified by labor group and annualized to reflect wage increases during the base period. These annualizations can be found on page 10.11.3.

3. The annualized December 2019 regular time, overtime, and premium pay expenses were then escalated prospectively by labor group to December 2021 (see page 10.11.5). Union and non-union costs were escalated using the contractual and target rates found on page 10.11.4.

4. Compensation related to the Annual Incentive Plan is included on a three-year average of the pay out percentage level. The Annual Incentive Plan is the second step of a two-stage compensation philosophy that provides certain employees with market average compensation with a portion at risk and based on achieving annual goals. Union employees do not participate in the Company's Annual Incentive Plan.

5. Pro Forma December 2021 pension and employee benefit expenses are based on either actuarial projections or are calculated by using actual December 2019 data escalated to December 2021. These expenses can be found on page 10.11.7.

6. Payroll tax calculations can be found on page 10.11.8.

Rocky Mountain Power
Utah General Rate Case - December 2021
WEBA – UMWA Correction

Account	Description	Co. Direct Filing Pro Forma 12 Months Ending December 2021	Co. Rebuttal Filing Pro Forma after adjustment 10.11 being applied 12 Months Ending December 2021	Incremental Adjustment	Ref.
5001XX	Regular Ordinary Time	458,620,326	458,620,326	-	
5002XX	Overtime	69,402,140	69,402,140	-	
5003XX	Premium Pay	10,741,974	10,741,974	-	
	Subtotal for Escalation	**538,764,440**	**538,764,440**	**-**	10.11.5
5005XX	Unused Leave Accrual	2,687,641	2,687,641	-	
500600	Temporary/Contract Labor	3,930	3,930	-	
500700	Severance Pay	(134,008)	(134,008)	-	
500850	Other Salary/Labor Costs	3,591,145	3,591,145	-	
50109X	Joint Owner Cutbacks	(1,277,093)	(1,277,093)	-	
	Subtotal Bare Labor	**543,636,055**	**543,636,055**	**-**	
500410	Annual Incentive Plan	29,777,703	29,777,703	-	
	Total Incentive	**29,777,703**	**29,777,703**	**-**	
500250	Overtime Meals	1,386,854	1,386,854	-	
500400	Bonus and Awards	1,776,665	1,776,665	-	
501325	Physical Exam	65,777	65,777	-	
502300	Education Assistance	133,630	133,630	-	
580899	Mining Salary/Benefit Credit	(192,027)	(192,027)	-	
	Total Other Labor	**3,170,899**	**3,170,899**	**-**	
	Subtotal Labor and Incentive	**576,584,657**	**576,584,657**	**-**	
50110X	Pensions	14,454,430	14,454,430	-	10.11.7
501115	SERP Plan	2,779,392	2,779,392	-	10.11.7
50115X	Post Retirement Benefits	3,718,875	1,321,376	(2,397,499)	10.11.7
501160	Post Employment Benefits	6,323,807	6,323,807	-	10.11.7
	Total Pensions	**27,276,503**	**24,879,004**	**(2,397,499)**	10.11.7
501102	Pension Administration	617,162	617,162	-	10.11.7
50112X	Medical	60,058,773	60,058,773	-	10.11.7
50117X	Dental	4,256,813	4,256,813	-	10.11.7
50120X	Vision	524,792	524,792	-	10.11.7
50122X	Life	823,517	823,517	-	10.11.7
50125X	401(k)	41,069,366	41,069,366	-	10.11.7
501251	401(k) Administration	814	814	-	10.11.7
501275	Accidental Death & Disability	37,367	37,367	-	10.11.7
501300	Long-Term Disability	4,121,246	4,121,246	-	10.11.7
5016XX	Worker's Compensation	1,530,314	1,530,314	-	10.11.7
502900	Other Salary Overhead	1,291,410	1,291,410	-	10.11.7
	Total Benefits	**114,331,574**	**114,331,574**	**-**	10.11.7
	Subtotal Pensions and Benefits	**141,608,078**	**139,210,579**	**(2,397,499)**	10.11.7
580XXX	Payroll Tax Expense	40,074,433	40,074,433	-	10.11.8
580700	Payroll Tax Expense-Unemployment	2,899,123	2,899,123	-	
	Total Payroll Taxes	**42,973,556**	**42,973,556**	**-**	
Total Labor		**761,166,291**	**758,768,792**	**(2,397,499)**	10.11.11
Non-Utility and Capitalized Labor		253,825,442	253,025,950	(799,492)	10.11.11
Total Utility Labor		**507,340,849**	**505,742,842**	**(1,598,007)**	10.11.11
		Ref. 10.11.11	Ref. 10.11.11	Ref. 10.11	

Rocky Mountain Power
Utah General Rate Case - December 2021
Escalation of Regular, Overtime, and Premium Labor
(Figures are in thousands)

Base Period: 12 Months Ended December 2019
Pro Forma: 12 Months Ending December 2021

Labor (12 Months Ending December 2021)

Acct	Account Desc.	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Total	
5001XX	Reg/Ordinary Time	37,941	34,185	34,420	35,938	38,092	33,452	37,541	35,799	34,686	38,344	35,095	35,978	**431,471**	
5002XX	Overtime	4,783	5,322	7,119	5,046	5,855	4,567	5,078	5,774	5,181	5,392	5,332	5,846	**65,294**	
5003XX	Premium Pay	516	822	750	1,004	919	839	902	1,035	906	874	906	632	**10,106**	
Grand Total		**43,240**	**40,329**	**42,288**	**41,987**	**44,866**	**38,859**	**43,521**	**42,608**	**40,774**	**44,610**	**41,333**	**42,456**	**506,871**	Ref. 10.11.6

Labor (12 Months Ending December 2021)

Group Code	Labor Group	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Total	
2	Officer/Exempt	16,574	15,349	16,052	15,437	17,432	14,555	16,734	16,414	14,990	17,307	15,965	16,246	193,055	
3	IBEW 125	3,432	3,207	3,329	3,240	3,328	2,965	3,349	3,274	3,122	3,409	3,156	3,472	39,283	
4	IBEW 659	4,070	4,024	4,526	3,483	3,838	3,334	3,703	3,590	3,868	3,693	3,518	3,722	45,370	
5	UWUA 197	176	165	265	160	179	162	180	128	172	180	156	216	2,139	
8	UWUA 127	4,380	3,763	4,112	4,345	4,848	3,951	4,284	4,132	4,150	4,295	3,988	4,493	50,740	
9	IBEW 57 WY	71	60	61	75	68	59	63	64	62	63	57	67	770	
11	IBEW 57 PD	8,823	8,456	8,191	9,635	9,448	8,671	9,506	9,529	8,996	9,541	8,868	8,568	108,232	
12	IBEW 57 PS	3,524	3,368	3,762	3,548	3,565	3,203	3,526	3,439	3,417	4,003	3,617	3,577	42,549	
13	PCCC Non-Exempt	705	591	593	610	599	548	573	478	487	507	470	533	6,694	
15	IBEW 57 CT	341	287	294	350	320	299	336	322	309	324	324	335	3,840	
16	IBEW 77	107	113	106	122	114	125	124	114	128	115	128	134	1,429	
18	Non-Exempt	1,037	946	997	983	1,128	988	1,144	1,125	1,073	1,172	1,085	1,094	12,770	
Grand Total		**43,240**	**40,329**	**42,288**	**41,987**	**44,866**	**38,859**	**43,521**	**42,608**	**40,774**	**44,610**	**41,333**	**42,456**	**506,871**	Ref. 10.11.6

Annualization Increase

Group Code	Labor Group	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	
2	Officer/Exempt	2.65%												(1)
3	IBEW 125	2.50%							5.10%					(1,4)
4	IBEW 659					2.50%		5.10%						(1,4)
5	UWUA 197						2.50%			5.80%				(1,4)
8	UWUA 127										2.25%			(1)
9	IBEW 57 WY							2.50%						(1)
11	IBEW 57 PD		2.50%											(1)
12	IBEW 57 PS		2.50%											(1)
13	PCCC Non-Exempt	1.73%												(1)
15	IBEW 57 CT		2.50%											(1)
16	IBEW 77		2.25%											(1)
18	Non-Exempt	2.15%												(1)

Annualized Labor December 2019

Group Code	Labor Group	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Total
2	Officer/Exempt	16,574	15,349	16,052	15,437	17,432	14,555	16,734	16,414	14,990	17,307	15,965	16,246	193,055
3	IBEW 125	3,607	3,371	3,499	3,405	3,498	3,116	3,520	3,274	3,122	3,409	3,156	3,472	40,449
4	IBEW 659	4,385	4,334	4,876	3,752	4,033	3,504	3,703	3,590	3,868	3,693	3,518	3,722	46,980
5	UWUA 197	190	179	287	173	194	171	190	135	172	180	156	216	2,246
8	UWUA 127	4,478	3,847	4,205	4,443	4,957	4,040	4,380	4,225	4,243	4,295	3,988	4,493	51,594
9	IBEW 57 WY	73	62	62	77	70	61	63	64	62	63	57	67	780
11	IBEW 57 PD	9,044	8,456	8,191	9,635	9,448	8,671	9,506	9,529	8,996	9,541	8,868	8,568	108,453
12	IBEW 57 PS	3,613	3,368	3,762	3,548	3,565	3,203	3,526	3,439	3,417	4,003	3,617	3,577	42,637
13	PCCC Non-Exempt	705	591	593	610	599	548	573	478	487	507	470	533	6,694
15	IBEW 57 CT	349	287	294	350	320	299	336	322	309	324	324	335	3,849
16	IBEW 77	110	113	106	122	114	125	124	114	128	115	128	134	1,432
18	Non-Exempt	1,037	946	997	983	1,128	988	1,144	1,125	1,073	1,172	1,085	1,094	12,770
Grand Total		**44,164**	**40,904**	**42,924**	**42,534**	**45,357**	**39,280**	**43,799**	**42,709**	**40,867**	**44,610**	**41,333**	**42,456**	**510,937**

Rocky Mountain Power
Utah General Rate Case - December 2021
Escalation of Regular, Overtime, and Premium Labor
(Figures are in thousands)

Base Period: 12 Months Ended December 2019
Pro Forma: 12 Months Ending December 2021

REDACTED

Pro Forma Increase to December 2021

Increases occur on the 26th of each month. For this exhibit, each increase is listed on the first day of the following month.

Group Code	Labor Group	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2	Officer/Exempt	[redacted]												
	12/26/2019													(1)
	12/26/2020													(1)
3	IBEW 125													
	1/26/2020													(1)
	1/26/2021													(1)
4	IBEW 659													
	4/26/2020													(1)
	4/26/2021													(3) CONF
5	UWUA 197													
	5/26/2020													(1)
	5/26/2021													(1)
8	UWUA 127													
	9/26/2020													(1)
	9/26/2021													(3) CONF
9	IBEW 57 WY													
	6/26/2020													(1,4)
	6/26/2021													(1)
11	IBEW 57 PD													
	1/26/2020													(1,4)
	1/26/2021													(1)
12	IBEW 57 PS													
	1/26/2020													(1,4)
	1/26/2021													(1)
13	PCCC Non-Exempt													
	12/26/2019													(1)
	12/26/2020													(2)
15	IBEW 57 CT													
	1/26/2020													(1,4)
	1/26/2021													(1)
16	IBEW 77													
	1/26/2020													(1)
	1/26/2021													(3) CONF
18	Non-Exempt													
	12/26/2019													(1)
	12/26/2020													(2)

(1) Labor increases supported by union contracts/actual increases.
(2) Projected labor increases supported by planned targets.
(3) Increase will be contingent on the future outcome of a new contract. (CONFIDENTIAL)
(4) A one-time spot increase

Rocky Mountain Power
Utah General Rate Case - December 2021
Escalation of Regular, Overtime, and Premium Labor
(Figures are in thousands)

Base Period: 12 Months Ended December 2019
Pro Forma: 12 Months Ending December 2021

REDACTED

Pro Forma Labor December 2021

Group Code	Labor Group	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Total
2	Officer/Exempt	[redacted]												
3	IBEW 125													
4	IBEW 659													
5	UWUA 197													
8	UWUA 127													
9	IBEW 57 WY													
11	IBEW 57 PD													
12	IBEW 57 PS													
13	PCCC Non-Exempt													
15	IBEW 57 CT													
16	IBEW 77													
18	Non-Exempt													
Grand Total		**44,164**	**40,904**	**42,924**	**42,534**	**45,357**	**39,280**	**43,799**	**42,709**	**40,867**	**44,610**	**41,333**	**42,456**	**510,937**

Ref. 10.11.2

Rocky Mountain Power
Utah General Rate Case - December 2021
WEBA – UMWA Correction
REDACTED

Composite Labor Increases

			Ref.
Regular Time/Overtime/Premium Pay Annualize - Actual	**506,871,148**		4.2.2
Regular Time/Overtime/Premium Pay December 2021 - Pro Forma	**510,937,285**	CAGR[1]	10.11.2
% Increase	0.80%	0.32%	

Miscellaneous Bare Labor Escalation

Description	Account	December 2019 Actual	Pro Forma Increase	December 2021 Pro Forma	Pro Forma Adjustment	Ref.
Unused Sick Leave Accrual	5005XX	2,528,541	0.80%	2,548,825	**20,284**	4.2.2
Joint Owner Cutbacks	50109X	(1,201,493)	0.80%	(1,211,132)	**(9,638)**	4.2.2
		1,327,048		1,337,693	10,646	

Annual Incentive Plan Escalation

Description	Account	December 2019 Actual	December 2021 Pro Forma	Pro Forma Adjustment	Ref.
Annual Incentive Plan Compensation	500410	[redacted]			10.11.2

Test Year Annual Incentive Plan (AIP) Calculation

	Officer/Exempt Actual Wages	[2]PCCC Non-Exempt Actual Wages	Non-Exempt Actual Wages	Total Wages	Actual AIP	AIP as a % of Wages
Cy 2017	[redacted]					
Cy 2018						
Cy 2019						
3-year Total	560,493,576			579,741,755	84,691,432	14.61%
Test Year	[redacted]					
	Ref 10.11.5				**Ref 10.11.2**	

[1]Compound Annual Growth Rate
[2] Effective CY 2018, Non-exempt are not eligible for AIP.

Rocky Mountain Power
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Account	Description	A Actual December 2019 Net of Joint Venture	B Actual December 2019 Gross	C Projected December 2021 Gross	D Projected December 2021 Net of Joint Venture	D - A Pro Forma Adjustment	Ref
50110X	Pensions	(5,405,331)	(5,289,589)	14,144,924	14,454,430	**19,859,760**	
501115	SERP Plan	2,946,562	2,946,562	2,779,392	2,779,392	**(167,170)**	
50115X	Post Retirement Benefits	(5,951,646)	(5,909,641)	1,312,050	1,321,376	**7,273,022**	10.11.2
501160	Post Employment Benefits	7,623,371	7,876,762	6,534,002	6,323,807	**(1,299,565)**	
	Subtotal	(787,044)	(375,905)	24,770,368	24,879,004	**25,666,048**	
501102	Pension Administration	538,662	555,490	636,442	617,162	**78,500**	
50112X	Medical	55,093,453	56,874,190	62,000,000	60,058,773	**4,965,320**	
50117X	Dental	3,676,335	3,799,996	4,400,000	4,256,813	**580,478**	
50120X	Vision	359,460	369,877	540,000	524,792	**165,332**	
50122X	Life	774,768	801,957	852,417	823,517	**48,750**	
50125X	401(k)	38,638,179	39,929,563	42,442,007	41,069,366	**2,431,187**	
501251	401(k) Administration	97	100	841	814	**717**	
501275	Accidental Death & Disability	35,155	35,443	37,673	37,367	**2,212**	
501300	Long-Term Disability	3,877,280	4,006,156	4,258,231	4,121,246	**243,966**	
5016XX	Worker's Compensation	1,439,724	1,485,704	1,579,187	1,530,314	**90,590**	
502900	Other Salary Overhead	1,291,410	1,292,480	1,292,480	1,291,410	**-**	
	Subtotal	105,724,522	109,150,956	118,039,278	114,331,574	**8,607,052**	
	Grand Total	**104,937,478**	108,775,050	142,809,646	**139,210,579**	**34,273,100**	10.11.2
		Ref. 4.2.2			Ref. 10.11.2		

Rocky Mountain Power
Utah General Rate Case - December 2021
WEBA – UMWA Correction
Payroll Tax Adjustment Calculation

FICA Calculated on December 2021 Pro Forma Labor			**Social Security (SS)**	**Medicare**	**Total**
Pro Forma Wages Adjustment	h		-	-	
Pro Forma Incentive Adjustment	i		-	-	
	j	h + i	-	-	
Percentage of SS eligible wages	k		91.92%	100.00%	
Total eligible wages	l	j * k	-	-	
Tax rate	m		6.20%	1.45%	
Tax on eligible wages	n	l * m	-	-	
Total FICA Tax - Incremental		n	-	-	-

Rocky Mountain Power
Utah General Rate Case - December 2021
WEBA – UMWA Correction
2020 Protocol FERC Spread

2020P Indicator	Direct Pro Forma 12 Months Ending December 2021	% Of Total	Rebuttal Pro Forma Adjustment	Pro Forma after adjustment 10.11 being applied 12 Months Ending December 2021	Utah Allocation %	Incremental Pro Forma Adjustment Utah Allocated	Incremental Pro Forma 12 Months Ending December 2021 Utah Allocated
500SG	14,421,991	1.895%	(45,426)	14,376,565	43.997%	(19,986)	6,325,329
502SG	21,175,225	2.782%	(66,697)	21,108,528	43.997%	(29,345)	9,287,224
503SE	125,023	0.016%	(394)	124,629	43.356%	(171)	54,034
505SG	963	0.000%	(3)	960	43.997%	(1)	422
506SG	34,865,780	4.581%	(109,819)	34,755,961	43.997%	(48,318)	15,291,753
510SG	3,654,413	0.480%	(11,511)	3,642,902	43.997%	(5,064)	1,602,786
511SG	8,852,123	1.163%	(27,882)	8,824,240	43.997%	(12,267)	3,882,445
512SG	28,470,363	3.740%	(89,675)	28,380,688	43.997%	(39,455)	12,486,793
513SG	13,183,839	1.732%	(41,526)	13,142,313	43.997%	(18,270)	5,782,289
514SG	2,716,806	0.357%	(8,557)	2,708,249	43.997%	(3,765)	1,191,562
535SG-P	5,772,179	0.758%	(18,181)	5,753,998	43.997%	(7,999)	2,531,615
535SG-U	3,736,044	0.491%	(11,768)	3,724,276	43.997%	(5,177)	1,638,588
536SG-P	29,792	0.004%	(94)	29,698	43.997%	(41)	13,066
537SG-P	593,816	0.078%	(1,870)	591,946	43.997%	(823)	260,441
537SG-U	29,494	0.004%	(93)	29,401	43.997%	(41)	12,936
539SG-P	7,341,874	0.965%	(23,125)	7,318,749	43.997%	(10,175)	3,220,067
539SG-U	5,876,433	0.772%	(18,509)	5,857,924	43.997%	(8,144)	2,577,340
540SG-P	225	0.000%	(1)	224	43.997%	(0)	99
541SG-P	-	0.000%	-	-	43.997%	-	-
542SG-P	265,394	0.035%	(836)	264,558	43.997%	(368)	116,399
542SG-U	11,899	0.002%	(37)	11,862	43.997%	(16)	5,219
543SG-P	428,391	0.056%	(1,349)	427,042	43.997%	(594)	187,888
543SG-U	343,788	0.045%	(1,083)	342,705	43.997%	(476)	150,782
544SG-P	1,001,151	0.132%	(3,153)	997,997	43.997%	(1,387)	439,094
544SG-U	231,631	0.030%	(730)	230,902	43.997%	(321)	101,591
545SG-P	895,201	0.118%	(2,820)	892,381	43.997%	(1,241)	392,625
545SG-U	96,654	0.013%	(304)	96,350	43.997%	(134)	42,392
546SG	4,574	0.001%	(14)	4,559	43.997%	(6)	2,006
548SG	6,471,597	0.850%	(20,384)	6,451,213	43.997%	(8,968)	2,838,372
549OR	39,735	0.005%	(125)	39,610	0.000%	-	-
549SG	4,612,433	0.606%	(14,528)	4,597,905	43.997%	(6,392)	2,022,963
552SG	937,427	0.123%	(2,953)	934,474	43.997%	(1,299)	411,145
553SG	1,884,154	0.248%	(5,935)	1,878,219	43.997%	(2,611)	826,369
554SG	95,461	0.013%	(301)	95,161	43.997%	(132)	41,868
556SG	495,907	0.065%	(1,562)	494,345	43.997%	(687)	217,499
557ID	50,191	0.007%	(158)	50,033	0.000%	-	-
557SG	32,403,756	4.257%	(102,064)	32,301,692	43.997%	(44,906)	14,211,936
560SG	7,415,823	0.974%	(23,358)	7,392,465	43.997%	(10,277)	3,252,500
561SG	11,039,890	1.450%	(34,773)	11,005,117	43.997%	(15,299)	4,841,976
562SG	2,115,046	0.278%	(6,662)	2,108,384	43.997%	(2,931)	927,636
563SG	558,320	0.073%	(1,759)	556,562	43.997%	(774)	244,873
566SG	51,274	0.007%	(162)	51,113	43.997%	(71)	22,488
567SG	181,940	0.024%	(573)	181,367	43.997%	(252)	79,797
568SG	1,159,795	0.152%	(3,653)	1,156,142	43.997%	(1,607)	508,674
569SG	3,413,360	0.448%	(10,751)	3,402,608	43.997%	(4,730)	1,497,063
570SG	7,745,141	1.018%	(24,395)	7,720,746	43.997%	(10,733)	3,396,935
571SG	3,933,779	0.517%	(12,391)	3,921,389	43.997%	(5,452)	1,725,313
572SG	29,021	0.004%	(91)	28,929	43.997%	(40)	12,728
580ID	(12,582)	-0.002%	40	(12,543)	0.000%	-	-
580OR	306,028	0.040%	(964)	305,064	0.000%	-	-
580SNPD	8,306,774	1.091%	(26,164)	8,280,610	48.488%	(12,687)	4,015,103
580UT	370,093	0.049%	(1,166)	368,927	100.000%	(1,166)	368,927
580WA	79,661	0.010%	(251)	79,410	0.000%	-	-
580WYP	114,230	0.015%	(360)	113,870	0.000%	-	-
581SNPD	13,358,508	1.755%	(42,076)	13,316,432	48.488%	(20,402)	6,456,873
582CA	33,016	0.004%	(104)	32,912	0.000%	-	-
582ID	281,040	0.037%	(885)	280,155	0.000%	-	-
582OR	263,035	0.035%	(829)	262,207	0.000%	-	-
582SNPD	2,624	0.000%	(8)	2,616	48.488%	(4)	1,268
582UT	1,158,428	0.152%	(3,649)	1,154,779	100.000%	(3,649)	1,154,779
582WA	111,344	0.015%	(351)	110,993	0.000%	-	-
582WYP	531,496	0.070%	(1,674)	529,822	0.000%	-	-
583CA	438,837	0.058%	(1,382)	437,455	0.000%	-	-
583ID	262,075	0.034%	(825)	261,249	0.000%	-	-
583OR	1,416,814	0.186%	(4,463)	1,412,351	0.000%	-	-
583SNPD	175	0.000%	(1)	174	48.488%	(0)	85
583UT	4,939,209	0.649%	(15,557)	4,923,651	100.000%	(15,557)	4,923,651
583WA	213,141	0.028%	(671)	212,470	0.000%	-	-
583WYP	372,409	0.049%	(1,173)	371,236	0.000%	-	-
583WYU	126,865	0.017%	(400)	126,465	0.000%	-	-
585SNPD	228,333	0.030%	(719)	227,613	48.488%	(349)	110,365
586CA	68,764	0.009%	(217)	68,547	0.000%	-	-
586ID	160,578	0.021%	(506)	160,072	0.000%	-	-
586OR	545,017	0.072%	(1,717)	543,300	0.000%	-	-

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586UT	706,940	0.093%	(2,227)	704,713	100.000%	(2,227)	704,713
586WA	267,108	0.035%	(841)	266,267	0.000%	-	-
586WYP	322,177	0.042%	(1,015)	321,162	0.000%	-	-
586WYU	88,377	0.012%	(278)	88,099	0.000%	-	-
587CA	507,560	0.067%	(1,599)	505,961	0.000%	-	-
587ID	759,062	0.100%	(2,391)	756,671	0.000%	-	-
587OR	4,831,445	0.635%	(15,218)	4,816,227	0.000%	-	-
587UT	4,556,667	0.599%	(14,352)	4,542,315	100.000%	(14,352)	4,542,315
587WA	984,086	0.129%	(3,100)	980,986	0.000%	-	-
587WYP	904,759	0.119%	(2,850)	901,909	0.000%	-	-
587WYU	88,835	0.012%	(280)	88,555	0.000%	-	-
588CA	48,380	0.006%	(152)	48,228	0.000%	-	-
588ID	(1,636)	0.000%	5	(1,631)	0.000%	-	-
588OR	13,470	0.002%	(42)	13,428	0.000%	-	-
588SNPD	3,433,001	0.451%	(10,813)	3,422,188	48.488%	(5,243)	1,659,351
588UT	(73,451)	-0.010%	231	(73,219)	100.000%	231	(73,219)
588WA	(721)	0.000%	2	(719)	0.000%	-	-
588WYP	9,972	0.001%	(31)	9,941	0.000%	-	-
588WYU	(51,249)	-0.007%	161	(51,088)	0.000%	-	-
589CA	15,349	0.002%	(48)	15,301	0.000%	-	-
589ID	11,004	0.001%	(35)	10,969	0.000%	-	-
589OR	74,871	0.010%	(236)	74,635	0.000%	-	-
589UT	315,510	0.041%	(994)	314,516	100.000%	(994)	314,516
589WA	12,610	0.002%	(40)	12,571	0.000%	-	-
589WYP	114,044	0.015%	(359)	113,685	0.000%	-	-
589WYU	6,960	0.001%	(22)	6,938	0.000%	-	-
590CA	106,778	0.014%	(336)	106,442	0.000%	-	-
590ID	174,690	0.023%	(550)	174,139	0.000%	-	-
590OR	844,570	0.111%	(2,660)	841,910	0.000%	-	-
590SNPD	2,764,491	0.363%	(8,708)	2,755,783	48.488%	(4,222)	1,336,225
590UT	1,386,758	0.182%	(4,368)	1,382,390	100.000%	(4,368)	1,382,390
590WA	172,936	0.023%	(545)	172,392	0.000%	-	-
590WYP	493,392	0.065%	(1,554)	491,838	0.000%	-	-
592CA	229,464	0.030%	(723)	228,742	0.000%	-	-
592ID	325,665	0.043%	(1,026)	324,640	0.000%	-	-
592OR	2,147,856	0.282%	(6,765)	2,141,091	0.000%	-	-
592SNPD	1,750,104	0.230%	(5,512)	1,744,592	48.488%	(2,673)	845,918
592UT	2,376,856	0.312%	(7,487)	2,369,369	100.000%	(7,487)	2,369,369
592WA	358,774	0.047%	(1,130)	357,644	0.000%	-	-
592WYP	780,059	0.102%	(2,457)	777,602	0.000%	-	-
592WYU	32,016	0.004%	(101)	31,915	0.000%	-	-
593CA	4,319,732	0.568%	(13,606)	4,306,126	0.000%	-	-
593ID	3,995,177	0.525%	(12,584)	3,982,593	0.000%	-	-
593OR	22,808,412	2.997%	(71,841)	22,736,571	0.000%	-	-
593SNPD	1,241,036	0.163%	(3,909)	1,237,127	48.488%	(1,895)	599,858
593UT	27,179,113	3.571%	(85,608)	27,093,505	100.000%	(85,608)	27,093,505
593WA	3,994,110	0.525%	(12,581)	3,981,530	0.000%	-	-
593WYP	3,855,771	0.507%	(12,145)	3,843,626	0.000%	-	-
593WYU	721,040	0.095%	(2,271)	718,769	0.000%	-	-
594CA	476,570	0.063%	(1,501)	475,069	0.000%	-	-
594ID	462,470	0.061%	(1,457)	461,014	0.000%	-	-
594OR	3,915,896	0.514%	(12,334)	3,903,562	0.000%	-	-
594SNPD	7,447	0.001%	(23)	7,424	48.488%	(11)	3,600
594UT	7,667,721	1.007%	(24,152)	7,643,569	100.000%	(24,152)	7,643,569
594WA	769,621	0.101%	(2,424)	767,197	0.000%	-	-
594WYP	726,698	0.095%	(2,289)	724,409	0.000%	-	-
594WYU	131,813	0.017%	(415)	131,398	0.000%	-	-
595SNPD	922,232	0.121%	(2,905)	919,327	48.488%	(1,408)	445,764
596CA	59,769	0.008%	(188)	59,580	0.000%	-	-
596ID	75,534	0.010%	(238)	75,296	0.000%	-	-
596OR	674,626	0.089%	(2,125)	672,502	0.000%	-	-
596UT	208,911	0.027%	(658)	208,253	100.000%	(658)	208,253
596WA	68,003	0.009%	(214)	67,788	0.000%	-	-
596WYP	255,516	0.034%	(805)	254,711	0.000%	-	-
596WYU	49,062	0.006%	(155)	48,908	0.000%	-	-
597CA	14,491	0.002%	(46)	14,445	0.000%	-	-
597ID	36,157	0.005%	(114)	36,043	0.000%	-	-
597OR	203,572	0.027%	(641)	202,930	0.000%	-	-
597SNPD	(121,722)	-0.016%	383	(121,339)	48.488%	186	(58,835)
597UT	197,265	0.026%	(621)	196,644	100.000%	(621)	196,644
597WA	14,035	0.002%	(44)	13,991	0.000%	-	-
597WYP	32,385	0.004%	(102)	32,283	0.000%	-	-
597WYU	16,623	0.002%	(52)	16,570	0.000%	-	-
598CA	7,192	0.001%	(23)	7,169	0.000%	-	-

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598OR	48,443	0.006%	(153)	48,290	0.000%	-	-
598SNPD	1,564,628	0.206%	(4,928)	1,559,699	48.488%	(2,390)	756,267
598WA	14,445	0.002%	(45)	14,399	0.000%	-	-
901CN	1,889,392	0.248%	(5,951)	1,883,441	47.809%	(2,845)	900,462
902CA	320,379	0.042%	(1,009)	319,370	0.000%	-	-
902CN	494,986	0.065%	(1,559)	493,427	47.809%	(745)	235,904
902ID	1,849,997	0.243%	(5,827)	1,844,170	0.000%	-	-
902OR	3,427,934	0.450%	(10,797)	3,417,137	0.000%	-	-
902UT	3,935,831	0.517%	(12,397)	3,923,434	100.000%	(12,397)	3,923,434
902WA	518,753	0.068%	(1,634)	517,119	0.000%	-	-
902WYP	898,613	0.118%	(2,830)	895,782	0.000%	-	-
902WYU	183,830	0.024%	(579)	183,251	0.000%	-	-
903CA	71,962	0.009%	(227)	71,735	0.000%	-	-
903CN	28,328,721	3.722%	(89,229)	28,239,492	47.809%	(42,660)	13,501,130
903ID	182,101	0.024%	(574)	181,528	0.000%	-	-
903OR	778,273	0.102%	(2,451)	775,821	0.000%	-	-
903UT	2,406,388	0.316%	(7,580)	2,398,808	100.000%	(7,580)	2,398,808
903WA	376,874	0.050%	(1,187)	375,687	0.000%	-	-
903WYP	424,730	0.056%	(1,338)	423,392	0.000%	-	-
903WYU	75,799	0.010%	(239)	75,561	0.000%	-	-
907CN	(9,583)	-0.001%	30	(9,553)	47.809%	14	(4,567)
908CA	2,863	0.000%	(9)	2,854	0.000%	-	-
908CN	2,315,301	0.304%	(7,293)	2,308,008	47.809%	(3,487)	1,103,445
908ID	(3)	0.000%	0	(3)	0.000%	-	-
908OR	2,267,715	0.298%	(7,143)	2,260,572	0.000%	-	-
908OTHER	61,685	0.008%	(194)	61,491	0.000%	-	-
908UT	2,670,105	0.351%	(8,410)	2,661,695	100.000%	(8,410)	2,661,695
908WA	378,693	0.050%	(1,193)	377,500	0.000%	-	-
908WYP	960,501	0.126%	(3,025)	957,475	0.000%	-	-
909CN	1,612,565	0.212%	(5,079)	1,607,486	47.809%	(2,428)	768,529
910CN	356	0.000%	(1)	354	47.809%	(1)	169
920OR	1	0.000%	(0.00)	0.50	0.000%	-	-
920SO	82,538,988	10.844%	(259,979)	82,279,009	43.595%	(113,337)	35,869,278
921SO	2,539,727	0.334%	(8,000)	2,531,728	43.595%	(3,487)	1,103,699
922SO	(24,920,861)	-3.274%	78,495	(24,842,366)	43.595%	34,220	(10,829,952)
925SO	-	0.000%	-	-	43.595%	-	-
928CA	24,242	0.003%	(76)	24,166	0.000%	-	-
928ID	37,191	0.005%	(117)	37,074	0.000%	-	-
928OR	144,693	0.019%	(456)	144,237	0.000%	-	-
928SO	510,894	0.067%	(1,609)	509,285	43.595%	(702)	222,021
928UT	100,870	0.013%	(318)	100,553	100.000%	(318)	100,553
928WA	268,118	0.035%	(845)	267,273	0.000%	-	-
928WYP	86,822	0.011%	(273)	86,549	0.000%	-	-
929SO	(3,606,695)	-0.474%	11,360	(3,595,334)	43.595%	4,952	(1,567,375)
935CA	1,285	0.000%	(4)	1,281	0.000%	-	-
935ID	1,700	0.000%	(5)	1,695	0.000%	-	-
935OR	12,652	0.002%	(40)	12,612	0.000%	-	-
935SO	2,237,629	0.294%	(7,048)	2,230,581	43.595%	(3,073)	972,415
935WA	300	0.000%	(1)	299	0.000%	-	-
935WYP	174	0.000%	(1)	173	0.000%	-	-
Utility Labor	**507,340,849**	**66.65309%**	**(1,598,007)**	**505,742,842**		**(704,738)**	**223,037,821**
						Ref 10.11	
Capital/Non Utility	253,825,442	33.34691%	(799,492)	253,025,950			
Total Labor	**761,166,291**	**100.00%**	**(2,397,499)**	**758,768,792**			
	Ref 10.11.2		Ref 10.11.2	Ref 10.11.2			

Rocky Mountain Power
Utah General Rate Case - December 2021
WEBA – CY 2021 Annualization

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED	REF#
Adjustment to Expense:							
Wage Annualization - CY 2021	Various	3	(1,583,208)	Various	Various	(698,211)	10.12.2

Description of Adjustment:

This adjustment accepts UAE's proposal to remove the annualized level of increases associated with CY 2021.

Rocky Mountain Power
Utah General Rate Case - December 2021
WEBA – CY 2021 Annualization

The unadjusted, annualized (12 months ended December 2019), and pro forma period (12 months ending December 2021) labor expenses are summarized on page 10.12.2. The following is an explanation of the procedures used to develop the labor benefits & expenses used in this adjustment.

1. Actual December 2019 total labor related expenses are identified on page 10.12.2, including bare labor, incentive, other labor, pensions, benefits, and payroll taxes.

2. Actual December 2019 expenses for regular time, overtime, and premium pay were identified by labor group and annualized to reflect wage increases during the base period. These annualizations can be found on page 10.12.3.

3. The annualized December 2019 regular time, overtime, and premium pay expenses were then escalated prospectively by labor group to December 2021 (see page 10.12.5). Union and non-union costs were escalated using the contractual and target rates found on page 10.12.4.

4. Compensation related to the Annual Incentive Plan is included on a three-year average of the pay out percentage level. The Annual Incentive Plan is the second step of a two-stage compensation philosophy that provides certain employees with market average compensation with a portion at risk and based on achieving annual goals. Union employees do not participate in the Company's Annual Incentive Plan.

5. Pro Forma December 2021 pension and employee benefit expenses are based on either actuarial projections or are calculated by using actual December 2019 data escalated to December 2021. These expenses can be found on page 10.12.7.

6. Payroll tax calculations can be found on page 10.12.8.

Rocky Mountain Power
Utah General Rate Case - December 2021
WEBA – CY 2021 Annualization

Account	Description	Co. Rebuttal Filing Pro Forma after adjustment 10.11 being applied 12 Months Ending December 2021	Co. Rebuttal Filing Pro Forma after adjustments 10.11 and 10.12 being applied 12 Months Ending December 2021	Incremental Adjustment	Ref.
5001XX	Regular Ordinary Time	458,620,326	456,879,300	(1,741,026)	
5002XX	Overtime	69,402,140	69,138,674	(263,466)	
5003XX	Premium Pay	10,741,974	10,701,195	(40,779)	
	Subtotal for Escalation	**538,764,440**	**536,719,169**	**(2,045,271)**	10.12.5
5005XX	Unused Leave Accrual	2,687,641	2,677,438	(10,203)	10.12.6
500600	Temporary/Contract Labor	3,930	3,930	-	
500700	Severance Pay	(134,008)	(134,008)	-	
500850	Other Salary/Labor Costs	3,591,145	3,591,145	-	
50109X	Joint Owner Cutbacks	(1,277,093)	(1,272,245)	4,848	10.12.6
	Subtotal Bare Labor	**543,636,055**	**541,585,429**	**(2,050,625)**	
500410	Annual Incentive Plan	29,777,703	29,777,703	-	10.12.6
	Total Incentive	**29,777,703**	**29,777,703**	**-**	
500250	Overtime Meals	1,386,854	1,386,854	-	
500400	Bonus and Awards	1,776,665	1,776,665	-	
501325	Physical Exam	65,777	65,777	-	
502300	Education Assistance	133,630	133,630	-	
580899	Mining Salary/Benefit Credit	(192,027)	(192,027)	-	
	Total Other Labor	**3,170,899**	**3,170,899**	**-**	
	Subtotal Labor and Incentive	**576,584,657**	**574,534,031**	**(2,050,625)**	
50110X	Pensions	14,454,430	14,454,430	-	10.12.7
501115	SERP Plan	2,779,392	2,779,392	-	10.12.7
50115X	Post Retirement Benefits	1,321,376	1,321,376	-	10.12.7
501160	Post Employment Benefits	6,323,807	6,323,807	-	10.12.7
	Total Pensions	**24,879,004**	**24,879,004**	**-**	10.12.7
501102	Pension Administration	617,162	617,162	-	10.12.7
50112X	Medical	60,058,773	60,058,773	-	10.12.7
50117X	Dental	4,256,813	4,256,813	-	10.12.7
50120X	Vision	524,792	524,792	-	10.12.7
50122X	Life	823,517	820,391	(3,126)	10.12.7
50125X	401(k)	41,069,366	40,913,457	(155,909)	10.12.7
501251	401(k) Administration	814	814	-	10.12.7
501275	Accidental Death & Disability	37,367	37,225	(142)	10.12.7
501300	Long-Term Disability	4,121,246	4,105,601	(15,645)	10.12.7
5016XX	Worker's Compensation	1,530,314	1,524,505	(5,809)	10.12.7
502900	Other Salary Overhead	1,291,410	1,291,410	-	10.12.7
	Total Benefits	**114,331,574**	**114,150,943**	**(180,631)**	10.12.7
	Subtotal Pensions and Benefits	**139,210,579**	**139,029,948**	**(180,631)**	10.12.7
580XXX	Payroll Tax Expense	40,074,433	39,930,393	(144,040)	10.12.8
580700	Payroll Tax Expense-Unemployment	2,899,123	2,899,123	-	
	Total Payroll Taxes	**42,973,556**	**42,829,517**	**(144,040)**	
Total Labor		**758,768,792**	**756,393,495**	**(2,375,296)**	10.12.11
Non-Utility and Capitalized Labor		253,025,950	252,233,862	(792,088)	10.12.11
Total Utility Labor		**505,742,842**	**504,159,634**	**(1,583,208)**	10.12.11
		Ref. 10.11.11	Ref.10.12.11	Ref. 10.12 Ref. 10.12.11	

Rocky Mountain Power
Utah General Rate Case - December 2021
Escalation of Regular, Overtime, and Premium Labor
(Figures are in thousands)

Base Period: 12 Months Ended December 2019
Pro Forma: 12 Months Ending December 2021

Labor (12 Months Ending December 2021)

Acct	Account Desc.	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Total	
5001XX	Reg/Ordinary Time	37,941	34,185	34,420	35,938	38,092	33,452	37,541	35,799	34,686	38,344	35,095	35,978	**431,471**	Ref. 10.12.2
5002XX	Overtime	4,783	5,322	7,119	5,046	5,855	4,567	5,078	5,774	5,181	5,392	5,332	5,846	**65,294**	Ref. 10.12.2
5003XX	Premium Pay	516	822	750	1,004	919	839	902	1,035	906	874	906	632	**10,106**	Ref. 10.12.2
Grand Total		**43,240**	**40,329**	**42,288**	**41,987**	**44,866**	**38,859**	**43,521**	**42,608**	**40,774**	**44,610**	**41,333**	**42,456**	**506,871**	Ref. 10.12.2

Labor (12 Months Ending December 2021)

Group Code	Labor Group	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Total	
2	Officer/Exempt	16,574	15,349	16,052	15,437	17,432	14,555	16,734	16,414	14,990	17,307	15,965	16,246	193,055	
3	IBEW 125	3,432	3,207	3,329	3,240	3,328	2,965	3,349	3,274	3,122	3,409	3,156	3,472	39,283	
4	IBEW 659	4,070	4,024	4,526	3,483	3,838	3,334	3,703	3,590	3,868	3,693	3,518	3,722	45,370	
5	UWUA 197	176	165	265	160	179	162	180	128	172	180	156	216	2,139	
8	UWUA 127	4,380	3,763	4,112	4,345	4,848	3,951	4,284	4,132	4,150	4,295	3,988	4,493	50,740	
9	IBEW 57 WY	71	60	61	75	68	59	63	64	62	63	57	67	770	
11	IBEW 57 PD	8,823	8,456	8,191	9,635	9,448	8,671	9,506	9,529	8,996	9,541	8,868	8,568	108,232	
12	IBEW 57 PS	3,524	3,368	3,762	3,548	3,565	3,203	3,526	3,439	3,417	4,003	3,617	3,577	42,549	
13	PCCC Non-Exempt	705	591	593	610	599	548	573	478	487	507	470	533	6,694	
15	IBEW 57 CT	341	287	294	350	320	299	336	322	309	324	324	335	3,840	
16	IBEW 77	107	113	106	122	114	125	124	114	128	115	128	134	1,429	
18	Non-Exempt	1,037	946	997	983	1,128	988	1,144	1,125	1,073	1,172	1,085	1,094	12,770	
Grand Total		**43,240**	**40,329**	**42,288**	**41,987**	**44,866**	**38,859**	**43,521**	**42,608**	**40,774**	**44,610**	**41,333**	**42,456**	**506,871**	Ref. 10.12.2

Annualization Increase

Group Code	Labor Group	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	
2	Officer/Exempt	2.65%												(1)
3	IBEW 125	2.50%							5.10%					(1,4)
4	IBEW 659					2.50%		5.10%						(1,4)
5	UWUA 197						2.50%			5.80%				(1,4)
8	UWUA 127										2.25%			(1)
9	IBEW 57 WY							2.50%						(1)
11	IBEW 57 PD		2.50%											(1)
12	IBEW 57 PS		2.50%											(1)
13	PCCC Non-Exempt	1.73%												(1)
15	IBEW 57 CT		2.50%											(1)
16	IBEW 77		2.25%											(1)
18	Non-Exempt	2.15%												(1)

Annualized Labor December 2019

Group Code	Labor Group	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Total
2	Officer/Exempt	16,573.624	15,349.463	16,052.463	15,436.896	17,431.887	14,554.674	16,733.684	16,413.814	14,989.731	17,307.338	15,965.410	16,245.712	193,054.697
3	IBEW 125	3,606.776	3,370.987	3,498.954	3,404.826	3,497.726	3,115.984	3,519.764	3,274.139	3,122.343	3,409.320	3,155.902	3,471.851	40,448.572
4	IBEW 659	4,384.881	4,334.497	4,876.246	3,752.222	4,033.300	3,504.183	3,702.878	3,590.328	3,868.026	3,693.240	3,518.117	3,721.748	46,979.664
5	UWUA 197	190.460	179.412	287.274	173.065	193.991	171.195	190.042	135.409	172.485	180.360	156.097	216.473	2,246.263
8	UWUA 127	4,478.103	3,847.381	4,204.705	4,442.585	4,957.142	4,040.263	4,380.310	4,224.790	4,243.017	4,294.582	3,987.986	4,493.128	51,593.992
9	IBEW 57 WY	72.913	61.604	62.484	76.710	69.628	60.567	62.652	63.851	61.619	63.363	57.452	66.781	779.624
11	IBEW 57 PD	9,043.810	8,456.163	8,190.657	9,635.246	9,447.795	8,671.401	9,505.958	9,529.406	8,995.604	9,540.630	8,867.668	8,568.219	108,452.558
12	IBEW 57 PS	3,612.503	3,367.535	3,761.979	3,548.387	3,564.905	3,202.662	3,526.234	3,438.718	3,416.917	4,003.355	3,617.291	3,577.005	42,637.492
13	PCCC Non-Exempt	704.917	591.080	592.891	610.030	599.205	547.686	573.156	477.689	487.477	506.807	470.392	532.801	6,694.130
15	IBEW 57 CT	349.284	286.691	293.522	350.001	320.421	298.532	336.331	322.325	309.207	323.810	324.173	334.685	3,848.982
16	IBEW 77	109.675	113.027	106.083	121.816	113.553	125.029	123.640	113.668	127.824	115.316	127.905	134.152	1,431.689
18	Non-Exempt	1,037.241	945.869	996.957	982.609	1,127.580	987.667	1,143.911	1,124.716	1,072.870	1,171.694	1,084.583	1,093.926	12,769.622
Grand Total		**44,164.186**	**40,903.710**	**42,924.215**	**42,534.394**	**45,357.132**	**39,279.843**	**43,798.559**	**42,708.853**	**40,867.120**	**44,609.816**	**41,332.977**	**42,456.481**	**510,937.285**

Rocky Mountain Power
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Docket No. 20-035-04
Witness: Steven R. McDougal

Rocky Mountain Power
Utah General Rate Case - December 2021
Escalation of Regular, Overtime, and Premium Labor
(Figures are in thousands)

Base Period: 12 Months Ended December 2019
Pro Forma: 12 Months Ending December 2021

REDACTED

Pro Forma Increase to December 2021

Increases occur on the 26th of each month. For this exhibit, each increase is listed on the first day of the following month.

Group Code	Labor Group	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2	Officer/Exempt	[redacted]												
	12/26/2019													(1)
	12/26/2020													(1)
3	IBEW 125													
	1/26/2020													(1)
	1/26/2021													(1)
4	IBEW 659													
	4/26/2020													(1)
	4/26/2021													(3) CONF
5	UWUA 197													
	5/26/2020													(1)
	5/26/2021													(1)
8	UWUA 127													
	9/26/2020													(1)
	9/26/2021													(3) CONF
9	IBEW 57 WY													
	6/26/2020													(1,4)
	6/26/2021													(1)
11	IBEW 57 PD													
	1/26/2020													(1,4)
	1/26/2021													(1)
12	IBEW 57 PS													
	1/26/2020													(1,4)
	1/26/2021													(1)
13	PCCC Non-Exempt													
	12/26/2019													(1)
	12/26/2020													(2)
15	IBEW 57 CT													
	1/26/2020													(1,4)
	1/26/2021													(1)
16	IBEW 77													
	1/26/2020													(1)
	1/26/2021													(3) CONF
18	Non-Exempt													
	12/26/2019													(1)
	12/26/2020													(2)

(1) Labor increases supported by union contracts/actual increases.
(2) Projected labor increases supported by planned targets.
(3) Increase will be contingent on the future outcome of a new contract. (CONFIDENTIAL)
(4) A one-time spot increase

Rocky Mountain Power
Utah General Rate Case - December 2021
Escalation of Regular, Overtime, and Premium Labor
(Figures are in thousands)

Base Period: 12 Months Ended December 2019
Pro Forma: 12 Months Ending December 2021

REDACTED

Pro Forma Labor December 2021

Group Code	Labor Group	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Total
2	Officer/Exempt	[redacted]												
3	IBEW 125													
4	IBEW 659													
5	UWUA 197													
8	UWUA 127													
9	IBEW 57 WY													
11	IBEW 57 PD													
12	IBEW 57 PS													
13	PCCC Non-Exempt													
15	IBEW 57 CT													
16	IBEW 77													
18	Non-Exempt													
Grand Total		**45,879.895**	**42,894.511**	**44,994.292**	**44,613.762**	**47,679.074**	**41,303.783**	**46,061.951**	**44,919.775**	**42,973.846**	**47,043.723**	**43,587.848**	**44,766.709**	**536,719.169**

Ref. 10.12.2

Rocky Mountain Power
Utah General Rate Case - December 2021
WEBA – CY 2021 Annualization
REDACTED

Composite Labor Increases

				Ref.
Regular Time/Overtime/Premium Pay Annualize - Actual		**506,871,148**		10.12.2
Regular Time/Overtime/Premium Pay December 2021 - Pro Forma		**536,719,169**	CAGR[1]	10.12.2
	% Increase	5.89%	2.32%	

Miscellaneous Bare Labor Escalation

Description	Account	December 2019 Actual	Pro Forma Increase	December 2021 Pro Forma	Pro Forma Adjustment	Ref.
Unused Sick Leave Accrual	5005XX	2,528,541	5.89%	2,677,438	**148,898**	10.12.2
Joint Owner Cutbacks	50109X	(1,201,493)	5.89%	(1,272,245)	**(70,752)**	10.12.2
		1,327,048		1,405,193	78,146	

Annual Incentive Plan Escalation

Description	Account	December 2019 Actual	December 2021 Pro Forma	Pro Forma Adjustment	Ref.
Annual Incentive Plan Compensation	500410	[redacted]	[redacted]		10.12.2

Test Year Annual Incentive Plan (AIP) Calculation

	Officer/Exempt Actual Wages	[2]PCCC Non-Exempt Actual Wages	Non-Exempt Actual Wages	Total Wages	Actual AIP	AIP as a % of Wages
Cy 2017	[redacted]					
Cy 2018						
Cy 2019						
3-year Total	560,493,576			579,741,755	84,691,432	14.61%
Test Year	[redacted]					
	Ref 10.12.5				Ref 10.12.2	

[1]Compound Annual Growth Rate
[2] Effective CY 2018, Non-exempt are not eligible for AIP.

Rocky Mountain Power
Utah General Rate Case - December 2021
WEBA – CY 2021 Annualization

		A	B	C	D	D - A	
Account	**Description**	**Actual December 2019 Net of Joint Venture**	**Actual December 2019 Gross**	**Projected December 2021 Gross**	**Projected December 2021 Net of Joint Venture**	**Pro Forma Adjustment**	**Ref**
50110X	Pensions	(5,405,331)	(5,289,589)	14,144,924	14,454,430	**19,859,760**	10.12.2
501115	SERP Plan	2,946,562	2,946,562	2,779,392	2,779,392	**(167,170)**	10.12.2
50115X	Post Retirement Benefits	(5,951,646)	(5,909,641)	1,312,050	1,321,376	**7,273,022**	10.12.2
501160	Post Employment Benefits	7,623,371	7,876,762	6,534,002	6,323,807	**(1,299,565)**	10.12.2
	Subtotal	(787,044)	(375,905)	24,770,368	24,879,004	**25,666,048**	10.12.2
501102	Pension Administration	538,662	555,490	636,442	617,162	**78,500**	10.12.2
50112X	Medical	55,093,453	56,874,190	62,000,000	60,058,773	**4,965,320**	10.12.2
50117X	Dental	3,676,335	3,799,996	4,400,000	4,256,813	**580,478**	10.12.2
50120X	Vision	359,460	369,877	540,000	524,792	**165,332**	10.12.2
50122X	Life	774,768	801,957	849,181	820,391	**45,624**	10.12.2
50125X	401(k)	38,638,179	39,929,563	42,280,888	40,913,457	**2,275,279**	10.12.2
501251	401(k) Administration	97	100	841	814	**717**	10.12.2
501275	Accidental Death & Disability	35,155	35,443	37,530	37,225	**2,070**	10.12.2
501300	Long-Term Disability	3,877,280	4,006,156	4,242,065	4,105,601	**228,321**	10.12.2
5016XX	Worker's Compensation	1,439,724	1,485,704	1,573,192	1,524,505	**84,781**	10.12.2
502900	Other Salary Overhead	1,291,410	1,292,480	1,292,480	1,291,410	**-**	10.12.2
	Subtotal	105,724,522	109,150,956	117,852,620	114,150,943	**8,426,421**	10.12.2
	Grand Total	**104,937,478**	108,775,050	142,622,988	**139,029,948**	**34,092,469**	10.12.2
		Ref. 10.12.2			Ref. 10.12.2	Ref. 10.12.2	

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Payroll Tax Adjustment Calculation

FICA Calculated on December 2021 Pro Forma Labor			**Social Security (SS)**	**Medicare**	**Total**	
Pro Forma Wages Adjustment	h		(2,040,423)	(2,040,423)		10.12.2
Pro Forma Incentive Adjustment	i		-	-		10.12.2
	j	h + i	(2,040,423)	(2,040,423)		
Percentage of SS eligible wages	k		92.02%	100.00%		
Total eligible wages	l	j * k	(1,877,557)	(2,040,423)		
Tax rate	m		6.20%	1.45%		
Tax on eligible wages	n	l * m	(116,409)	(29,586)		
Total FICA Tax - Incremental		n	(116,409)	(29,586)	**(145,995)**	10.12.2

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2020P Indicator	Pro Forma after adjustment 10.11 being applied 12 Months Ending	% Of Total	Rebuttal Pro Forma Adjustment	Pro Forma after adjustments 10.11 and 10.12 being applied 12 Months Ending December 2021	Utah Allocation %	Incremental Pro Forma Adjustment Utah Allocated	Incremental Pro Forma 12 Months Ending December 2021 Utah Allocated
500SG	14,376,565	1.895%	(45,005)	14,331,560	43.997%	(19,801)	6,305,528
502SG	21,108,528	2.782%	(66,079)	21,042,448	43.997%	(29,073)	9,258,151
503SE	124,629	0.016%	(390)	124,239	43.356%	(169)	53,865
505SG	960	0.000%	(3)	957	43.997%	(1)	421
506SG	34,755,961	4.581%	(108,802)	34,647,159	43.997%	(47,870)	15,243,883
510SG	3,642,902	0.480%	(11,404)	3,631,498	43.997%	(5,017)	1,597,768
511SG	8,824,240	1.163%	(27,624)	8,796,616	43.997%	(12,154)	3,870,291
512SG	28,380,688	3.740%	(88,845)	28,291,843	43.997%	(39,089)	12,447,703
513SG	13,142,313	1.732%	(41,142)	13,101,172	43.997%	(18,101)	5,764,188
514SG	2,708,249	0.357%	(8,478)	2,699,771	43.997%	(3,730)	1,187,832
535SG-P	5,753,998	0.758%	(18,013)	5,735,986	43.997%	(7,925)	2,523,690
535SG-U	3,724,276	0.491%	(11,659)	3,712,618	43.997%	(5,130)	1,633,459
536SG-P	29,698	0.004%	(93)	29,605	43.997%	(41)	13,025
537SG-P	591,946	0.078%	(1,853)	590,093	43.997%	(815)	259,626
537SG-U	29,401	0.004%	(92)	29,309	43.997%	(40)	12,895
539SG-P	7,318,749	0.965%	(22,911)	7,295,838	43.997%	(10,080)	3,209,986
539SG-U	5,857,924	0.772%	(18,338)	5,839,586	43.997%	(8,068)	2,569,272
540SG-P	224	0.000%	(1)	223	43.997%	(0)	98
541SG-P	-	0.000%	-	-	43.997%	-	-
542SG-P	264,558	0.035%	(828)	263,729	43.997%	(364)	116,034
542SG-U	11,862	0.002%	(37)	11,825	43.997%	(16)	5,202
543SG-P	427,042	0.056%	(1,337)	425,705	43.997%	(588)	187,299
543SG-U	342,705	0.045%	(1,073)	341,632	43.997%	(472)	150,310
544SG-P	997,997	0.132%	(3,124)	994,873	43.997%	(1,375)	437,719
544SG-U	230,902	0.030%	(723)	230,179	43.997%	(318)	101,273
545SG-P	892,381	0.118%	(2,794)	889,588	43.997%	(1,229)	391,396
545SG-U	96,350	0.013%	(302)	96,048	43.997%	(133)	42,259
546SG	4,559	0.001%	(14)	4,545	43.997%	(6)	2,000
548SG	6,451,213	0.850%	(20,195)	6,431,018	43.997%	(8,885)	2,829,487
549OR	39,610	0.005%	(124)	39,486	0.000%	-	-
549SG	4,597,905	0.606%	(14,394)	4,583,512	43.997%	(6,333)	2,016,630
552SG	934,474	0.123%	(2,925)	931,549	43.997%	(1,287)	409,858
553SG	1,878,219	0.248%	(5,880)	1,872,339	43.997%	(2,587)	823,782
554SG	95,161	0.013%	(298)	94,863	43.997%	(131)	41,737
556SG	494,345	0.065%	(1,548)	492,797	43.997%	(681)	216,818
557ID	50,033	0.007%	(157)	49,877	0.000%	-	-
557SG	32,301,692	4.257%	(101,119)	32,200,573	43.997%	(44,490)	14,167,446
560SG	7,392,465	0.974%	(23,142)	7,369,323	43.997%	(10,182)	3,242,318
561SG	11,005,117	1.450%	(34,451)	10,970,665	43.997%	(15,158)	4,826,818
562SG	2,108,384	0.278%	(6,600)	2,101,783	43.997%	(2,904)	924,732
563SG	556,562	0.073%	(1,742)	554,820	43.997%	(767)	244,107
566SG	51,113	0.007%	(160)	50,953	43.997%	(70)	22,418
567SG	181,367	0.024%	(568)	180,799	43.997%	(250)	79,547
568SG	1,156,142	0.152%	(3,619)	1,152,523	43.997%	(1,592)	507,081
569SG	3,402,608	0.448%	(10,652)	3,391,957	43.997%	(4,686)	1,492,376
570SG	7,720,746	1.018%	(24,169)	7,696,576	43.997%	(10,634)	3,386,301
571SG	3,921,389	0.517%	(12,276)	3,909,113	43.997%	(5,401)	1,719,912
572SG	28,929	0.004%	(91)	28,839	43.997%	(40)	12,688
580ID	(12,543)	-0.002%	39	(12,503)	0.000%	-	-
580OR	305,064	0.040%	(955)	304,109	0.000%	-	-
580SNPD	8,280,610	1.091%	(25,922)	8,254,687	48.488%	(12,569)	4,002,534
580UT	368,927	0.049%	(1,155)	367,772	100.000%	(1,155)	367,772
580WA	79,410	0.010%	(249)	79,161	0.000%	-	-
580WYP	113,870	0.015%	(356)	113,514	0.000%	-	-
581SNPD	13,316,432	1.755%	(41,687)	13,274,745	48.488%	(20,213)	6,436,660
582CA	32,912	0.004%	(103)	32,809	0.000%	-	-
582ID	280,155	0.037%	(877)	279,278	0.000%	-	-
582OR	262,207	0.035%	(821)	261,386	0.000%	-	-
582SNPD	2,616	0.000%	(8)	2,608	48.488%	(4)	1,264
582UT	1,154,779	0.152%	(3,615)	1,151,164	100.000%	(3,615)	1,151,164
582WA	110,993	0.015%	(347)	110,646	0.000%	-	-
582WYP	529,822	0.070%	(1,659)	528,163	0.000%	-	-
583CA	437,455	0.058%	(1,369)	436,086	0.000%	-	-
583ID	261,249	0.034%	(818)	260,432	0.000%	-	-
583OR	1,412,351	0.186%	(4,421)	1,407,930	0.000%	-	-
583SNPD	174	0.000%	(1)	174	48.488%	(0)	84
583UT	4,923,651	0.649%	(15,413)	4,908,238	100.000%	(15,413)	4,908,238
583WA	212,470	0.028%	(665)	211,805	0.000%	-	-
583WYP	371,236	0.049%	(1,162)	370,074	0.000%	-	-
583WYU	126,465	0.017%	(396)	126,069	0.000%	-	-
585SNPD	227,613	0.030%	(713)	226,901	48.488%	(345)	110,020
586CA	68,547	0.009%	(215)	68,332	0.000%	-	-
586ID	160,072	0.021%	(501)	159,571	0.000%	-	-
586OR	543,300	0.072%	(1,701)	541,599	0.000%	-	-
586UT	704,713	0.093%	(2,206)	702,507	100.000%	(2,206)	702,507
586WA	266,267	0.035%	(834)	265,433	0.000%	-	-

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586WYP	321,162	0.042%	(1,005)	320,156	0.000%	-	-
586WYU	88,099	0.012%	(276)	87,823	0.000%	-	-
587CA	505,961	0.067%	(1,584)	504,377	0.000%	-	-
587ID	756,671	0.100%	(2,369)	754,303	0.000%	-	-
587OR	4,816,227	0.635%	(15,077)	4,801,150	0.000%	-	-
587UT	4,542,315	0.599%	(14,220)	4,528,095	100.000%	(14,220)	4,528,095
587WA	980,986	0.129%	(3,071)	977,915	0.000%	-	-
587WYP	901,909	0.119%	(2,823)	899,085	0.000%	-	-
587WYU	88,555	0.012%	(277)	88,278	0.000%	-	-
588CA	48,228	0.006%	(151)	48,077	0.000%	-	-
588ID	(1,631)	0.000%	5	(1,626)	0.000%	-	-
588OR	13,428	0.002%	(42)	13,386	0.000%	-	-
588SNPD	3,422,188	0.451%	(10,713)	3,411,475	48.488%	(5,195)	1,654,156
588UT	(73,219)	-0.010%	229	(72,990)	100.000%	229	(72,990)
588WA	(719)	0.000%	2	(717)	0.000%	-	-
588WYP	9,941	0.001%	(31)	9,910	0.000%	-	-
588WYU	(51,088)	-0.007%	160	(50,928)	0.000%	-	-
589CA	15,301	0.002%	(48)	15,253	0.000%	-	-
589ID	10,969	0.001%	(34)	10,935	0.000%	-	-
589OR	74,635	0.010%	(234)	74,402	0.000%	-	-
589UT	314,516	0.041%	(985)	313,531	100.000%	(985)	313,531
589WA	12,571	0.002%	(39)	12,531	0.000%	-	-
589WYP	113,685	0.015%	(356)	113,329	0.000%	-	-
589WYU	6,938	0.001%	(22)	6,917	0.000%	-	-
590CA	106,442	0.014%	(333)	106,108	0.000%	-	-
590ID	174,139	0.023%	(545)	173,594	0.000%	-	-
590OR	841,910	0.111%	(2,636)	839,275	0.000%	-	-
590SNPD	2,755,783	0.363%	(8,627)	2,747,157	48.488%	(4,183)	1,332,042
590UT	1,382,390	0.182%	(4,328)	1,378,062	100.000%	(4,328)	1,378,062
590WA	172,392	0.023%	(540)	171,852	0.000%	-	-
590WYP	491,838	0.065%	(1,540)	490,298	0.000%	-	-
592CA	228,742	0.030%	(716)	228,025	0.000%	-	-
592ID	324,640	0.043%	(1,016)	323,623	0.000%	-	-
592OR	2,141,091	0.282%	(6,703)	2,134,388	0.000%	-	-
592SNPD	1,744,592	0.230%	(5,461)	1,739,130	48.488%	(2,648)	843,270
592UT	2,369,369	0.312%	(7,417)	2,361,952	100.000%	(7,417)	2,361,952
592WA	357,644	0.047%	(1,120)	356,525	0.000%	-	-
592WYP	777,602	0.102%	(2,434)	775,168	0.000%	-	-
592WYU	31,915	0.004%	(100)	31,815	0.000%	-	-
593CA	4,306,126	0.568%	(13,480)	4,292,645	0.000%	-	-
593ID	3,982,593	0.525%	(12,467)	3,970,125	0.000%	-	-
593OR	22,736,571	2.997%	(71,176)	22,665,395	0.000%	-	-
593SNPD	1,237,127	0.163%	(3,873)	1,233,255	48.488%	(1,878)	597,981
593UT	27,093,505	3.571%	(84,815)	27,008,690	100.000%	(84,815)	27,008,690
593WA	3,981,530	0.525%	(12,464)	3,969,066	0.000%	-	-
593WYP	3,843,626	0.507%	(12,032)	3,831,594	0.000%	-	-
593WYU	718,769	0.095%	(2,250)	716,519	0.000%	-	-
594CA	475,069	0.063%	(1,487)	473,582	0.000%	-	-
594ID	461,014	0.061%	(1,443)	459,570	0.000%	-	-
594OR	3,903,562	0.514%	(12,220)	3,891,342	0.000%	-	-
594SNPD	7,424	0.001%	(23)	7,400	48.488%	(11)	3,588
594UT	7,643,569	1.007%	(23,928)	7,619,641	100.000%	(23,928)	7,619,641
594WA	767,197	0.101%	(2,402)	764,796	0.000%	-	-
594WYP	724,409	0.095%	(2,268)	722,141	0.000%	-	-
594WYU	131,398	0.017%	(411)	130,987	0.000%	-	-
595SNPD	919,327	0.121%	(2,878)	916,449	48.488%	(1,395)	444,368
596CA	59,580	0.008%	(187)	59,394	0.000%	-	-
596ID	75,296	0.010%	(236)	75,060	0.000%	-	-
596OR	672,502	0.089%	(2,105)	670,396	0.000%	-	-
596UT	208,253	0.027%	(652)	207,601	100.000%	(652)	207,601
596WA	67,788	0.009%	(212)	67,576	0.000%	-	-
596WYP	254,711	0.034%	(797)	253,914	0.000%	-	-
596WYU	48,908	0.006%	(153)	48,754	0.000%	-	-
597CA	14,445	0.002%	(45)	14,400	0.000%	-	-
597ID	36,043	0.005%	(113)	35,930	0.000%	-	-
597OR	202,930	0.027%	(635)	202,295	0.000%	-	-
597SNPD	(121,339)	-0.016%	380	(120,959)	48.488%	184	(58,651)
597UT	196,644	0.026%	(616)	196,028	100.000%	(616)	196,028
597WA	13,991	0.002%	(44)	13,947	0.000%	-	-
597WYP	32,283	0.004%	(101)	32,182	0.000%	-	-
597WYU	16,570	0.002%	(52)	16,518	0.000%	-	-
598CA	7,169	0.001%	(22)	7,147	0.000%	-	-
598OR	48,290	0.006%	(151)	48,139	0.000%	-	-
598SNPD	1,559,699	0.206%	(4,883)	1,554,817	48.488%	(2,367)	753,900
598WA	14,399	0.002%	(45)	14,354	0.000%	-	-
901CN	1,883,441	0.248%	(5,896)	1,877,545	47.809%	(2,819)	897,643

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902CA	319,370	0.042%	(1,000)	318,370	0.000%	-	-
902CN	493,427	0.065%	(1,545)	491,882	47.809%	(738)	235,166
902ID	1,844,170	0.243%	(5,773)	1,838,397	0.000%	-	-
902OR	3,417,137	0.450%	(10,697)	3,406,440	0.000%	-	-
902UT	3,923,434	0.517%	(12,282)	3,911,151	100.000%	(12,282)	3,911,151
902WA	517,119	0.068%	(1,619)	515,500	0.000%	-	-
902WYP	895,782	0.118%	(2,804)	892,978	0.000%	-	-
902WYU	183,251	0.024%	(574)	182,677	0.000%	-	-
903CA	71,735	0.009%	(225)	71,511	0.000%	-	-
903CN	28,239,492	3.722%	(88,403)	28,151,089	47.809%	(42,265)	13,458,866
903ID	181,528	0.024%	(568)	180,959	0.000%	-	-
903OR	775,821	0.102%	(2,429)	773,393	0.000%	-	-
903UT	2,398,808	0.316%	(7,509)	2,391,299	100.000%	(7,509)	2,391,299
903WA	375,687	0.050%	(1,176)	374,511	0.000%	-	-
903WYP	423,392	0.056%	(1,325)	422,067	0.000%	-	-
903WYU	75,561	0.010%	(237)	75,324	0.000%	-	-
907CN	(9,553)	-0.001%	30	(9,523)	47.809%	14	(4,553)
908CA	2,854	0.000%	(9)	2,845	0.000%	-	-
908CN	2,308,008	0.304%	(7,225)	2,300,783	47.809%	(3,454)	1,099,990
908ID	(3)	0.000%	0	(3)	0.000%	-	-
908OR	2,260,572	0.298%	(7,077)	2,253,495	0.000%	-	-
908OTHER	61,491	0.008%	(192)	61,298	0.000%	-	-
908UT	2,661,695	0.351%	(8,332)	2,653,362	100.000%	(8,332)	2,653,362
908WA	377,500	0.050%	(1,182)	376,318	0.000%	-	-
908WYP	957,475	0.126%	(2,997)	954,478	0.000%	-	-
909CN	1,607,486	0.212%	(5,032)	1,602,453	47.809%	(2,406)	766,123
910CN	354	0.000%	(1)	353	47.809%	(1)	169
920OR	1	0.000%	(0.00)	0.50	0.000%	-	-
920SO	82,279,009	10.844%	(257,571)	82,021,438	43.595%	(112,287)	35,756,990
921SO	2,531,728	0.334%	(7,925)	2,523,802	43.595%	(3,455)	1,100,244
922SO	(24,842,366)	-3.274%	77,768	(24,764,598)	43.595%	33,903	(10,796,049)
925SO	-	0.000%	-	-	43.595%	-	-
928CA	24,166	0.003%	(76)	24,090	0.000%	-	-
928ID	37,074	0.005%	(116)	36,958	0.000%	-	-
928OR	144,237	0.019%	(452)	143,785	0.000%	-	-
928SO	509,285	0.067%	(1,594)	507,691	43.595%	(695)	221,326
928UT	100,553	0.013%	(315)	100,238	100.000%	(315)	100,238
928WA	267,273	0.035%	(837)	266,437	0.000%	-	-
928WYP	86,549	0.011%	(271)	86,278	0.000%	-	-
929SO	(3,595,334)	-0.474%	11,255	(3,584,079)	43.595%	4,907	(1,562,468)
935CA	1,281	0.000%	(4)	1,277	0.000%	-	-
935ID	1,695	0.000%	(5)	1,690	0.000%	-	-
935OR	12,612	0.002%	(39)	12,572	0.000%	-	-
935SO	2,230,581	0.294%	(6,983)	2,223,598	43.595%	(3,044)	969,371
935WA	299	0.000%	(1)	298	0.000%	-	-
935WYP	173	0.000%	(1)	173	0.000%	-	-
Utility Labor	**505,742,842**	**66.65309%**	**(1,583,208)**	**504,159,634**		**(698,211)**	**222,339,610**
						Ref 10.12	
Capital/Non Utility	253,025,950	33.34691%	(792,088)	252,233,862			
Total Labor	**758,768,792**	**100.00%**	**(2,375,296)**	**756,393,495**			
	Ref 10.12.2		Ref 10.12.2	Ref 10.12.2			

Rocky Mountain Power
Utah General Rate Case - December 2021
Rebuttal Net Power Cost Alignment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED	REF#
Adjustment to Revenue:							
Sales for Resale (Account 447)							
Post-Merger Firm	447NPC	3	(315,431)	SG	43.997%	(138,782)	10.13.1
Adjustment to Expense:							
Purchased Power (Account 555)							
Post-merger Firm	555NPC	3	925,574	SG	43.997%	407,229	10.13.1
Wheeling Expense (Account 565)							
Post-merger Firm	565NPC	3	(99,698,854)	SG	43.997%	(43,865,001)	10.13.1
Non-Firm	565NPC	3	99,698,837	SE	43.356%	43,225,637	10.13.1
			(16)			(639,365)	
Fuel Expense (Accounts 501, 503, 547)							
Fuel Consumed - Coal	501NPC	3	7,569,383	SE	43.356%	3,281,798	10.13.1
Fuel Consumed - Gas	501NPC	3	(224)	SE	43.356%	(97)	10.13.1
Natural Gas Consumed	547NPC	3	378,157	SE	43.356%	163,955	10.13.1
Simple Cycle Combustion Turbines	547NPC	3	(92)	SE	43.356%	(40)	10.13.1
			7,947,225			3,445,615	

Description of Adjustment:

This adjustment is modified to reflect the updated in-service dates of the TB Flats and Pryor Mountain wind projects.

Rocky Mountain Power PAGE 10.13.1
Utah General Rate Case - December 2021
Rebuttal Net Power Cost Alignment

	ACCOUNT	Type	FILED TOTAL COMPANY	REBUTTAL TOTAL COMPANY	INCRMENTAL TOTAL COMPANY	2020 P Factor	REF#
Adjustment to Revenue:							
Sales for Resale (Account 447)							
Existing Firm PPL	447NPC	3	-	-	-	SG	10.13.2
Existing Firm UPL	447NPC	3	-	-	-	SG	10.13.2
Post-Merger Firm	447NPC	3	41,322,243	41,006,812	(315,431)	SG	10.13.2
Non-Firm	447NPC	3	4,130,399	4,130,399	-	SE	10.13.2
Total Sales for Resale			45,452,642	45,137,211	(315,431)		
Adjustment to Expense:							
Purchased Power (Account 555)							
Existing Firm Demand PPL	555NPC	3	9,085,775	9,085,775	-	SG	10.13.2
Existing Firm Demand UPL	555NPC	3	13,749,771	13,749,771	-	SG	10.13.2
Existing Firm Energy	555NPC	3	50,516,280	50,516,280	-	SE	10.13.2
Post-merger Firm	555NPC	3	(135,439,970)	(134,514,396)	925,574	SG	10.13.2
Post-merger Firm - Situs	555NPC	3	(4,879,895)	(4,879,895)	-	UT	10.13.2
Secondary Purchases	555NPC	3	15,254,142	15,254,142	-	SE	10.13.2
Seasonal Contracts	555NPC	3	-	-	-	SG	10.13.2
Other Generation	555NPC	3	-	-	-	SG	10.13.2
Total Purchased Power Adjustments:			(51,713,898)	(50,788,324)	925,574		
Wheeling Expense (Account 565)							
Existing Firm PPL	565NPC	3	21,908,441	21,908,441	-	SG	10.13.2
Existing Firm UPL	565NPC	3	-	-	-	SG	10.13.2
Post-merger Firm	565NPC	3	(23,026,866)	(122,725,719)	(99,698,854)	SG	10.13.2
Non-Firm	565NPC	3	2,043,998	101,742,835	99,698,837	SE	10.13.2
Total Wheeling Expense Adjustments:			925,572	925,556	(16)		
Fuel Expense (Accounts 501, 503, 547)							
Fuel - Overburden Amortization - Idaho	501NPC	3	(115,324)	(115,324)	-	ID	10.13.2
Fuel - Overburden Amortization - Wyom	501NPC	3	(324,493)	(324,493)	-	WY	10.13.2
Fuel Consumed - Coal	501NPC	3	(71,073,493)	(63,504,110)	7,569,383	SE	10.13.2
Fuel Consumed - Gas	501NPC	3	(2,813,682)	(2,813,905)	(224)	SE	10.13.2
Steam from Other Sources	503NPC	3	(339,252)	(339,252)	-	SE	10.13.2
Natural Gas Consumed	547NPC	3	12,855,887	13,234,044	378,157	SE	10.13.2
Simple Cycle Combustion Turbines	547NPC	3	1,037,726	1,037,635	(92)	SE	10.13.2
Cholla / APS Exchange	501NPC	3	(38,598,189)	(38,598,189)	-	SE	10.13.2
Total Fuel Expense Adjustments:			(99,370,820)	(91,423,595)	7,947,225		
Total Power Cost Adjustment			(195,611,787)	(186,423,574)	9,188,213		
Post-merger Firm Type 1	555NPC	1	(33,256,288)	(33,256,288)	-	SG	10.13.2
Utah Situs NPC Adjustments	555NPC	3	1,570,674	1,570,674	-	UT	10.13.2

Rocky Mountain Power
Utah General Rate Case - December 2021
Rebuttal Net Power Cost Alignment

Description	FERC Account	(1) Total Account (B Tabs)	(2) Remove Non-NPC / NPC Mechanism Accruals	(3) Unadjusted NPC (1) + (2)	(4) Type 1 Adjustments	(5) Normalized NPC (3) + (4)	(6) Type 3 Pro Forma NPC	(7) Type 3 Adjustment (6) - (5)	2020P Protocol Factor
Sales for Resale (Account 447)									
Existing Firm Sales PPL	447.12	-	-	-	-	-	-	-	SG
Existing Firm Sales UPL	447.122	-	-	-	-	-	-	-	SG
Post-merger Firm Sales	447.13, .14, .20, .61, .62	182,171,613	-	182,171,613	-	182,171,613	223,178,425	41,006,812	SG
Non-firm Sales	447.5	(4,130,399)	-	(4,130,399)	-	(4,130,399)	-	4,130,399	SE
Transmission Services	447.9	83,550	(83,550)	-	-	-	-	-	S
On-system Wholesale Sales	447.1	14,146,893	(14,146,893)	-	-	-	-	-	S
Total Revenue Adjustments		192,271,657	(14,230,443)	178,041,214	-	178,041,214	223,178,425	45,137,211	
Purchased Power (Account 555)									
Existing Firm Demand PPL	555.66	-	-	-	-	-	9,085,775	9,085,775	SG
Existing Firm Demand UPL	555.68	-	-	-	-	-	13,749,771	13,749,771	SG
Existing Firm Energy	555.65, 555.69	-	-	-	-	-	50,516,280	50,516,280	SE
Post-merger Firm	555.26, .55, .59, .61, .62, .63, .64, .67, .8	695,109,638	-	695,109,638	-	695,109,638	527,338,954	(167,770,684)	SG
Post-merger Firm - Situs	555.27	4,879,895	-	4,879,895	-	4,879,895	-	(4,879,895)	Situs
Secondary Purchases	555.7, 555.25	(15,254,142)	-	(15,254,142)	-	(15,254,142)	-	15,254,142	SE
NPC Deferral Mechanism	555.57	(52,470,478)	52,470,478	-	-	-	-	-	OTHER
Seasonal Contracts		-	-	-	-	-	-	-	SG
Wind Integration Charge		-	-	-	-	-	-	-	SG
RPS Compliance Purchases	555.22,555.23,555.24	930,470	(930,470)	-	-	-	-	-	OTHER
BPA Regional Adjustments	555.11, 555.12, 555.133	-	-	-	-	-	-	-	S
Post-merger Firm Type 1		-	-	-	(33,256,288)	(33,256,288)	-	33,256,288	SG
Total Purchased Power Adjustment		633,195,384	51,540,008	684,735,392	(33,256,288)	651,479,104	600,690,780	(50,788,324)	
Wheeling (Account 565)									
Existing Firm PPL	565.26	-	-	-	-	-	21,908,441	21,908,441	SG
Existing Firm UPL	565.27	-	-	-	-	-	-	-	SG
Post-merger Firm	565.0, 565.46, 565.1	140,890,496	-	140,890,496	-	140,890,496	18,164,776	(122,725,719)	SG
Non-firm	565.25	4,934,772	-	4,934,772	-	4,934,772	106,677,607	101,742,835	SE
Total Wheeling Expense Adjustment		145,825,268	-	145,825,268	-	145,825,268	146,750,824	925,556	
Fuel Expense (Accounts 501, 503 and 547)									
Fuel - Overburden Amortization - Idaho	501.12	115,324	-	115,324	-	115,324	-	(115,324)	ID
Fuel - Overburden Amortization - Wyoming	501.12	324,493	-	324,493	-	324,493	-	(324,493)	WY
Fuel Consumed - Coal	501.1	666,132,702	-	666,132,702	-	666,132,702	602,628,592	(63,504,110)	SE
Fuel Consumed - Gas	501.35	7,470,166	-	7,470,166	-	7,470,166	4,656,260	(2,813,905)	SE
Steam From Other Sources	503	4,836,772	-	4,836,772	-	4,836,772	4,497,520	(339,252)	SE
Natural Gas Consumed	547.1	279,047,502	-	279,047,502	-	279,047,502	292,281,546	13,234,044	SE
Simple Cycle Combustion Turbines	547.1	1,160,580	-	1,160,580	-	1,160,580	2,198,215	1,037,635	SE
Cholla/APS Exchange	501.1	38,598,189	-	38,598,189	-	38,598,189	-	(38,598,189)	SE
Fuel Regulatory Costs Deferral and Amort	501.15	4,028,247	(4,028,247)	-	-	-	-	-	S
Fuel Regulatory Costs Deferral and Amort	501.15	(1,147,393)	1,147,393	-	-	-	-	-	SE
Miscellaneous Fuel Costs	501.0, .2, .3, .4, .45, .5, .51	16,363,336	(16,363,336)	-	-	-	-	-	SE
Miscellaneous Fuel Costs - Cholla	501.2,501.45	2,888,332	(2,888,332)	-	-	-	-	-	SE
Total Fuel Expense		1,019,818,249	(22,132,521)	997,685,728	-	997,685,728	906,262,133	(91,423,595)	
Net Power Cost		**1,606,567,244**	**43,637,929**	**1,650,205,173**	**(33,256,288)**	**1,616,948,886**	**1,430,525,312**	**(186,423,574)**	
					Ref 10.13		**Ref 10.13.4**	**Ref 10.13**	

Rocky Mountain Power
Utah General Rate Case - December 2021
Rebuttal Net Power Cost Alignment

Study Results
MERGED PEAK/ENERGY SPLIT
($)

Period Ending
Dec-21

	Merged 01/21-12/21	Pre-Merger Demand	Pre-Merger Energy	Non-Firm	Post-Merger
SPECIAL SALES FOR RESALE					
Pacific Pre Merger	-	-	-	-	-
Post Merger	223,178,425	-	-	-	223,178,425
Utah Pre Merger	-	-	-	-	-
NonFirm Sub Total	-	-	-	-	-
TOTAL SPECIAL SALES	223,178,425	-	-	-	223,178,425
PURCHASED POWER & NET INTERCHANGE					
BPA Peak Purchase	-	-	-	-	-
Pacific Capacity	-	-	-	-	-
Mid Columbia	1,762,136	528,641	1,233,495	-	-
Misc/Pacific	154,785	32,097	122,688	-	-
Q.F. Contracts/PPL	156,943,720	8,525,037	41,535,225	-	106,883,458
Small Purchases west	-	-	-	-	-
Pacific Sub Total	158,860,641	9,085,775	42,891,408	-	106,883,458
Gemstate	1,717,824	-	1,717,824	-	-
GSLM	-	-	-	-	-
QF Contracts/UPL	178,421,420	13,749,771	5,892,759	-	158,778,889
IPP Layoff	-	-	-	-	-
Small Purchases east	14,288	-	14,288	-	-
UP&L to PP&L	-	-	-	-	-
Utah Sub Total	180,153,532	13,749,771	7,624,871	-	158,778,889
APS Supplemental	-	-	-	-	-
Avoided Cost Resource	-	-	-	-	-
BPA Reserve Purchase	-	-	-	-	-
Cedar Springs Wind	11,723,273	-	-	-	11,723,273
Cedar Springs Wind III	8,908,095	-	-	-	8,908,095
Combine Hills Wind	5,369,068	-	-	-	5,369,068
Cove Mountain Solar	3,863,906	-	-	-	3,863,906
Cove Mountain Solar II	343,571	-	-	-	343,571
Deseret Purchase	32,990,071	-	-	-	32,990,071
Eagle Mountain - UAMPS/UMPA	2,615,653	-	-	-	2,615,653
Georgia-Pacific Camas	-	-	-	-	-
Hermiston Purchase	-	-	-	-	-
Hunter Solar	7,122,324	-	-	-	7,122,324
Hurricane Purchase	160,742	-	-	-	160,742
MagCorp	-	-	-	-	-
MagCorp Reserves	5,084,680	-	-	-	5,084,680
Milican Solar	2,646,179	-	-	-	2,646,179
Milford Solar	7,081,219	-	-	-	7,081,219
Nucor	7,129,800	-	-	-	7,129,800
Monsanto Reserves	19,999,999	-	-	-	19,999,999
Prineville Solar	1,795,505	-	-	-	1,795,505
Rock River Wind	3,949,010	-	-	-	3,949,010
Sigurd Solar	2,905,571	-	-	-	2,905,571
Three Buttes Wind	20,662,796	-	-	-	20,662,796
Top of the World Wind	40,686,138	-	-	-	40,686,138
Tri-State Purchase	-	-	-	-	-
Wolverine Creek Wind	10,259,065	-	-	-	10,259,065
BPA So. Idaho	-	-	-	-	-
PSCo Exchange	5,400,000	-	-	-	5,400,000
West Valley Toll	-				-

Rocky Mountain Power
Utah General Rate Case - December 2021
Rebuttal Net Power Cost Alignment

Study Results
MERGED PEAK/ENERGY SPLIT
($)

Period Ending
Dec-21

	Merged 01/21-12/21	Pre-Merger Demand	Pre-Merger Energy	Non-Firm	Post-Merger
Seasonal Purchased Power					
Constellation 2013-2016	-	-	-	-	-
System Balancing Purchases	59,885,544	-	-	-	59,885,544
Short Term Firm Purchases	1,094,400	-	-	-	1,094,400
New Firm Sub Total	261,676,608	-	-	-	261,676,608
Integration Charge	-	-	-	-	-
Non Firm Sub Total	-	-	-	-	-
TOTAL PURCHASED PW & NET INT.	600,690,780	22,835,546	50,516,280	-	527,338,954
WHEELING & U. OF F. EXPENSE					
Pacific Firm Wheeling and Use of Facilities	21,908,441	21,908,441	-	-	-
Utah Firm Wheeling and Use of Facilities	-	-	-	-	-
Post Merger	18,164,776	-	-	-	18,164,776
Nonfirm Wheeling	106,677,607	-	-	106,677,607	-
TOTAL WHEELING & U. OF F. EXPENSE	146,750,824	21,908,441	-	106,677,607	18,164,776
THERMAL FUEL BURN EXPENSE					
Carbon	-	-	-	-	-
Cholla	-	-	-	-	-
Colstrip	15,189,735	-	-	15,189,735	-
Craig	16,859,969	-	-	16,859,969	-
Chehalis	57,776,721	-	-	57,776,721	-
Currant Creek	47,143,780	-	-	47,143,780	-
Dave Johnston	49,911,159	-	-	49,911,159	-
Gadsby	4,656,260	-	-	4,656,260	-
Gadsby CT	2,198,215	-	-	2,198,215	-
Hayden	14,706,480	-	-	14,706,480	-
Hermiston	25,317,021	-	-	25,317,021	-
Hunter	93,768,329	-	-	93,768,329	-
Huntington	99,698,837	-	-	99,698,837	-
Jim Bridger	209,704,601	-	-	209,704,601	-
Lake Side 1	70,386,404	-	-	70,386,404	-
Lake Side 2	63,977,364	-	-	63,977,364	-
Naughton - Gas	27,680,257	-	-	27,680,257	-
Naughton	77,018,796	-	-	77,018,796	-
Wyodak	25,770,686	-	-	25,770,686	-
TOTAL FUEL BURN EXPENSE	901,764,613	-	-	901,764,613	-
OTHER GENERATION EXPENSE					
Blundell	4,497,520	-	-	4,497,520	-
TOTAL OTHER GEN. EXPENSE	4,497,520	-	-	4,497,520	-
NET POWER COST	**1,430,525,312**	**44,743,987**	**50,516,280**	**1,012,939,740**	**322,325,305**
	Ref 10.13.1				

Rocky Mountain Power
Utah General Rate Case - December 2021
Rebuttal Net Power Cost Alignment
UtahSitus Adjustments

	Total	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21
Total Impact	**1,570,674**	116,525	130,478	206,981	247,136	261,925	156,446	(28,697)	(27,718)	57,320	184,530	147,023	118,725

Rocky Mountain Power
Utah General Rate Case - December 2021
Nodal Pricing Model Update

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED	REF#
Adjustment to Expense:							
Other Expenses	557	3	-	SG			
Intangible Plant Amortization	404IP	3	16,923	SG	43.997%	7,446	10.14.1
Adjustment to Rate Base:							
Miscellaneous Intangible Plant	303	3	467,230	SG	43.997%	205,570	10.14.1
Accum. Amort. for Intangible Plant	111IP	3	(9,166)	SG	43.997%	(4,033)	10.14.1
Adjustment to Tax:							
Schedule M Adjustment	SCHMAT	1	16,923	SG	43.997%	7,446	
Schedule M Adjustment	SCHMDT	1	207,684	SG	43.997%	91,376	
Deferred Inc Tax Exp	41110	1	(4,161)	SG	43.997%	(1,831)	
Deferred Inc Tax Exp	41010	1	51,062	SG	43.997%	22,466	
ADIT Balance - 13 MA 2021	282	1	(52,507)	SG	43.997%	(23,102)	

Description of Adjustment:

This adjustment adds the software related rate base and on-going O&M costs for the Nodal Pricing Model as agreed upon in the Multi-State Process filed in Docket No. 19-035-42, Appendix D. As part of the Company's response to UAE 3.9 1st REVISED the estimated in-service amount of this project increased from $4.0 million to $4.5 million. This incremental adjustment captures that change.

Rocky Mountain Power
Utah General Rate Case - December 2021
Nodal Pricing Model Update

	Account	As Filed Total Company	Rebuttal Update Total Company	Adjustment	Ref
Adjustment to Expense:					
Other Expenses	557	500,000	500,000	-	10.14.2
Intangible Plant Amortization	404IP	144,876	161,799	16,923	10.14.2
Adjustment to Rate Base:					
Miscellaneous Intangible Plant	303	4,000,000	4,467,230	467,230	10.14.2
Accum. Amort. for Intangible Plant	111IP	(78,474)	(87,641)	(9,166)	10.14.2
Adjustment to Tax:					
Schedule M Adjustment	SCHMAT	144,876	161,799	16,923	
Schedule M Adjustment	SCHMDT	1,778,004	1,985,688	207,684	
Deferred Inc Tax Exp	41110	(35,620)	(39,781)	(4,161)	
Deferred Inc Tax Exp	41010	437,151	488,213	51,062	
ADIT Balance - 13 MA 2021	282	(449,500)	(502,007)	(52,507)	

Rocky Mountain Power
Utah General Rate Case - December 2021
Nodal Pricing Model Update

Electric Plant in Service

	Account	Factor	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	13 MA Dec-21	
Intangible (Software)	303	SG	4,000,000	4,000,000	4,000,000	4,000,000	4,000,000	4,000,000	4,000,000	4,000,000	4,000,000	4,000,000	4,000,000	4,000,000	4,000,000	4,000,000	**Ref. 10.14.1**

Amortization Expense*

	Account	Factor	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	12 ME Dec-21	
Intangible Plant Amortization	404IP	SG	6,036	12,073	12,073	12,073	12,073	12,073	12,073	12,073	12,073	12,073	12,073	12,073	12,073	144,876	**Ref. 10.14.1**

Amortization Reserve

	Account	Factor	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	13 MA Dec-21	
Accum. Amort. for Intangible Plant	111IP	SG	(6,036)	(18,109)	(30,182)	(42,255)	(54,328)	(66,401)	(78,474)	(90,547)	(102,620)	(114,693)	(126,766)	(138,839)	(150,912)	(78,474)	**Ref. 10.14.1**

Incorporating the revised Nodal Pricing in-service balance

Electric Plant in Service

	Account	Factor	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	13 MA Dec-21	
Intangible (Software)	303	SG	4,467,230	4,467,230	4,467,230	4,467,230	4,467,230	4,467,230	4,467,230	4,467,230	4,467,230	4,467,230	4,467,230	4,467,230	4,467,230	4,467,230	**Ref. 10.14.1**

Amortization Expense*

	Account	Factor	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	12 ME Dec-21	
Intangible Plant Amortization	404IP	SG	6,742	13,483	13,483	13,483	13,483	13,483	13,483	13,483	13,483	13,483	13,483	13,483	13,483	161,799	**Ref. 10.14.1**

Amortization Reserve

	Account	Factor	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	13 MA Dec-21	
Accum. Amort. for Intangible Plant	111IP	SG	(6,742)	(20,225)	(33,708)	(47,191)	(60,674)	(74,158)	(87,641)	(101,124)	(114,607)	(128,091)	(141,574)	(155,057)	(168,540)	(87,641)	**Ref. 10.14.1**

**2020 Composite Depreciation Rate - Intangible*	*3.622%*
**2021 Composite Depreciation Rate - Intangible*	*3.622%*

Rocky Mountain Power
Utah General Rate Case - December 2021
Nodal Pricing Model Update

Project	Date	Project Capital Amount	
Intangible Plant			
CAISO Implementation Fee	12/31/2020	$ 1,000,000	
ESM System Upgrades	12/31/2020	$ 906,000	
Settlement System Upgrades	12/31/2020	$ 1,585,000	
Internal Capitalized IT Labor	12/31/2020	$ 509,000	
		$ 4,000,000	**Ref 10.14.2**
Updated projected new Capital Additions added since filing the UT GRC	12/31/2020	**$ 4,467,230**	**Ref 10.14.2**
Incremental Adjustment		**$ 467,230**	

Incremental O&M	
ESM Maintenance and Licenses	$ 200,000
Settlements Maintenance and Licenses	$ 300,000
	$ 500,000

Rocky Mountain Power
Utah General Rate Case - December 2021
Other Decommissioning Cost – Colstrip - Correction
REDACTED

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED	REF#
Adjustment to Expense							
Annual Incremental Decomm. Costs	407	3	[redacted]	SG	43.997%	[redacted]	10.15.1
Adjustment to Rate Base							
Accum. Reg Liab. - Incr. Decomm.	254	3	[redacted]	SG	43.997%	[redacted]	10.15.1
Adjustment to Tax:							
Schedule M Adjustment	SCHMAT	3	[redacted]	SG	43.997%	[redacted]	10.15.1
Deferred Income Tax Expense	41110	3		SG	43.997%		10.15.1
Accumulated Def Inc Tax Balance	190	3		SG	43.997%		10.15.1

Description of Adjustment:

This adjustment corrects the remaining life calculation for the Colstrip plant to the appropriate seven years.

Rocky Mountain Power
Utah General Rate Case - December 2021
Other Decommissioning Cost – Colstrip - Correction
REDACTED

	Account	As Filed Total Company	Rebuttal Update Total Company	Adjustment	REF#
Adjustment to Expense					
Annual Incremental Decomm. Costs	407	[redacted]			10.15.2
Adjustment to Rate Base					
Accum. Reg Liab. - Incr. Decomm.	254	[redacted]			10.15.2
Adjustment to Tax:					
Schedule M Adjustment	SCHMAT	[redacted]			10.15.2
Deferred Income Tax Expense	41110				10.15.2
Accumulated Def Inc Tax Balance	190				10.15.2

Rocky Mountain Power
Utah General Rate Case - December 2021
Other Decommissioning Cost – Colstrip - Correction
REDACTED

Plant	Plant Closure Date	Remaining Life (Years)	Incremental Decommissioning Costs	Total Company Annual Amount
Hunter	2042	22.00	[redacted]	
Huntington	2036	16.00		
Dave Johnston	2027	7.00		
Jim Bridger	2037	17.00		
Naughton	2029	9.00		
Wyodak	2039	19.00		
Hayden	2030	10.00		
Colstrip	2027	7.00		
			Total	[redacted]
				Ref 10.15.1

	407 Mthly Accum.	SCHMAT Tax	41110 Def Inc Tax Exp	254 Reg. Liab.	190 ADIT
Dec-20	-			-	-
Jan-21	[redacted]				
Feb-21					
Mar-21					
Apr-21					
May-21					
Jun-21					
Jul-21					
Aug-21					
Sep-21					
Oct-21					
Nov-21					
Dec-21					
Annual Total	[redacted]				
		Page 10.15.1	**Page 10.15.1**		
			13 Mo. Avg.	[redacted]	
				Page 10.15.1	**Page 10.15.1**

Rocky Mountain Power
Utah General Rate Case - December 2021
Electric Plant Acquisition Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED	REF#
Adjustment to Expense:							
Elec. Plant Acq. Amort. Exp.	406	3	(4,706,208)	SG	43.997%	(2,070,614)	10.16.1
Adjustment to Rate Base:							
Gross Electric Plant Acquisition Adj	114	3	-	SG	43.997%	-	10.16.1
Elec. Plant Acq. Acc. Amort.	115	3	(3,882,321)	SG	43.997%	(1,708,124)	10.16.1
Adjustment to Tax:							
Schedule M Adjustment	SCHMAT	3	(4,706,208)	SCHMDEXP	43.474%	(2,045,999)	
Def Inc Tax Expense	41110	3	1,157,097	SCHMDEXP	43.474%	503,042	

Description of Adjustment:

This adjustment accepts the adjustment proposed by OCS that the Protected PP&E EDIT Amortization Regulatory Liability be used to buy-down the remaining unamortized balance of the Craig and Hayden electric plant acquisition adjustment.

Rocky Mountain Power
Utah General Rate Case - December 2021
Electric Plant Acquisition Adjustment

PAGE 10.16.1

	ACCOUNT	Type	Factor	AS FILED TOTAL COMPANY	INCREMENTAL TOTAL COMPANY	REBUTTAL TOTAL COMPANY	REF#
Adjustment to Rate Base:							
Electric Plant Acquisition Adj	114	3	SG	144,704,699	-	144,704,699	10.16.2
Elec. Plant Acq. Acc. Amort.	115	3	SG	(137,980,477)	(3,882,321)	(141,862,798)	10.16.2
				6,724,222	(3,882,321)	2,841,901	
Adjustment to Depreciation Expense:							
Elec. Plant Acq. Amort. Exp.	406	3	SG	4,781,559	(4,706,208)	75,351	10.16.2

Rocky Mountain Power
Utah General Rate Case - December 2021
Regulatory Asset Amortization
Electric Plant Acquisition Adjustment

Page 10.16.2

Adjust Base Period to Pro Forma Period

	Amortization	Rate Base: Gross Acq.	Rate Base: Acc Amort
Pro Forma Amount (below)	75,351	144,704,699	(141,862,798)
Base Period Amount (below)	4,781,559	144,704,699	(128,417,358)
Pro Forma Adjustment	**(4,706,208)**	**-**	**(13,445,440)**
	Ref. 8.6	**Ref. 8.6**	**Ref. 8.6**

		Gross Acquisition	Beg Balance Accumulated Amortization	Amortization	TCJA Buy-Down Craig/Hayden	End Balance Accumulated Amortization	13 Month Avg Bal Gross Acq	13 Month Avg Bal Acc Amort
	Opening Balance	144,704,699				(126,026,579)		
2019	January	144,704,699	(126,026,579)	(398,463)		(126,425,042)		
	February	144,704,699	(126,425,042)	(398,463)		(126,823,505)		
	March	144,704,699	(126,823,505)	(398,463)		(127,221,969)		
	April	144,704,699	(127,221,969)	(398,463)		(127,620,432)		
	May	144,704,699	(127,620,432)	(398,463)		(128,018,895)		
	June	144,704,699	(128,018,895)	(398,463)		(128,417,358)		
	July	144,704,699	(128,417,358)	(398,463)		(128,815,822)		
	August	144,704,699	(128,815,822)	(398,463)		(129,214,285)		
	September	144,704,699	(129,214,285)	(398,463)		(129,612,748)		
	October	144,704,699	(129,612,748)	(398,463)		(130,011,212)		
	November	144,704,699	(130,011,212)	(398,463)		(130,409,675)		
	December	144,704,699	(130,409,675)	(398,463)		(130,808,138)	144,704,699	**(128,417,358)**
			Base Period Amort =	**(4,781,559)**				
2020	January	144,704,699	(130,808,138)	(398,463)		(131,206,601)		
	February	144,704,699	(131,206,601)	(398,463)		(131,605,065)		
	March	144,704,699	(131,605,065)	(398,463)		(132,003,528)		
	April	144,704,699	(132,003,528)	(398,463)		(132,401,991)		
	May	144,704,699	(132,401,991)	(398,463)		(132,800,454)		
	June	144,704,699	(132,800,454)	(398,463)		(133,198,918)		
	July	144,704,699	(133,198,918)	(398,463)		(133,597,381)		
	August	144,704,699	(133,597,381)	(398,463)		(133,995,844)		
	September	144,704,699	(133,995,844)	(398,463)		(134,394,308)		
	October	144,704,699	(134,394,308)	(398,463)		(134,792,771)		
	November	144,704,699	(134,792,771)	(398,463)		(135,191,234)		
	December	144,704,699	(135,191,234)	(398,463)	(6,235,425)	(141,825,123)		
2021	January	144,704,699	(141,825,123)	(6,279)		(141,831,402)		
	February	144,704,699	(141,831,402)	(6,279)		(141,837,681)		
	March	144,704,699	(141,837,681)	(6,279)		(141,843,960)		
	April	144,704,699	(141,843,960)	(6,279)		(141,850,240)		
	May	144,704,699	(141,850,240)	(6,279)		(141,856,519)		
	June	144,704,699	(141,856,519)	(6,279)		(141,862,798)		
	July	144,704,699	(141,862,798)	(6,279)		(141,869,078)		
	August	144,704,699	(141,869,078)	(6,279)		(141,875,357)		
	September	144,704,699	(141,875,357)	(6,279)		(141,881,636)		
	October	144,704,699	(141,881,636)	(6,279)		(141,887,915)		
	November	144,704,699	(141,887,915)	(6,279)		(141,894,195)		
	December	144,704,699	(141,894,195)	(6,279)		(141,900,474)	144,704,699	**(141,862,798)**
			Pro Forma Amort =	**(75,351)**				

Rocky Mountain Power
Utah General Rate Case - December 2021
Regulatory Asset Amortization
Electric Plant Acquisition Adjustment

	Amort Period 5/92 - 4/22		**Amort Period 2/10 - 7/54**		**Amort Period 12/16-12/65**			
	Original Amount	**141,186,242**	**Original Amount**	**1,981,728**	**Original Amount**	**1,536,728**	**Gross Total**	**144,704,699**
	Craig/Hayden		**Twin Cities 69kV Line**		**Idaho Power Asset Exchange**			
MONTH	MONTHLY AMORT.	ACCUM. AMORT. BALANCE	MONTHLY AMORT.	ACCUM. AMORT. BALANCE	MONTHLY AMORT.	ACCUM. AMORT. BALANCE	TOTAL MONTHLY AMORT	ACCUM. AMORT. BALANCE TOTAL
Dec-20	(6,627,609)	(141,186,242)	(3,718)	(485,207)	(2,561)	(153,673)	(6,633,888)	(141,825,122)
Jan-21	0	(141,186,242)	(3,718)	(488,925)	(2,561)	(156,234)	(6,279)	(141,831,402)
Feb-21	0	(141,186,242)	(3,718)	(492,643)	(2,561)	(158,796)	(6,279)	(141,837,681)
Mar-21	0	(141,186,242)	(3,718)	(496,361)	(2,561)	(161,357)	(6,279)	(141,843,960)
Apr-21	0	(141,186,242)	(3,718)	(500,079)	(2,561)	(163,918)	(6,279)	(141,850,240)
May-21	0	(141,186,242)	(3,718)	(503,797)	(2,561)	(166,479)	(6,279)	(141,856,519)
Jun-21	0	(141,186,242)	(3,718)	(507,515)	(2,561)	(169,040)	(6,279)	(141,862,798)
Jul-21	0	(141,186,242)	(3,718)	(511,233)	(2,561)	(171,602)	(6,279)	(141,869,077)
Aug-21	0	(141,186,242)	(3,718)	(514,951)	(2,561)	(174,163)	(6,279)	(141,875,357)
Sep-21	0	(141,186,242)	(3,718)	(518,669)	(2,561)	(176,724)	(6,279)	(141,881,636)
Oct-21	0	(141,186,242)	(3,718)	(522,388)	(2,561)	(179,285)	(6,279)	(141,887,915)
Nov-21	0	(141,186,242)	(3,718)	(526,106)	(2,561)	(181,847)	(6,279)	(141,894,194)
Dec-21	0	(141,186,242)	(3,718)	(529,824)	(2,561)	(184,408)	(6,279)	(141,900,474)

Rocky Mountain Power
Utah General Rate Case - December 2021
Property Tax Update

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED	REF#
Adjustment to Expense:							
Taxes Other Than Income	408	3	10,086,000	GPS	43.595%	4,396,960	10.17.1

Description of Adjustment:

This incremental adjustment reflects the difference between the filed property taxes and the revised property taxes, which used the updated 2020 capitalization rates.

Utah General Rate Case - December 2021
Estimated Property Tax Expense for December 2021
Property Tax Update

FERC Account	G/L Account	As Filed Total Company	Rebuttal Update Total Company	Incremental	Ref
408.15	579000	148,789,387	148,789,387	-	
Total Accrued Property Tax - 12 Months End. December 2019		148,789,387	148,789,387	-	
Forecasted Property Tax Exp. for the Twelve Months Ending December 2021		181,328,000	191,414,000	10,086,000	
Less Accrued Property Tax - 12 Months Ended December 31, 2019		(148,789,387)	(148,789,387)	-	
Incremental Adjustment to Property Taxes		**32,538,613**	**42,624,613**	**10,086,000**	**10.17**

Rocky Mountain Power
Utah General Rate Case - December 2021
Pro Forma Tax Update

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED	REF#
Adjustment to Tax:							
ADIT Balance 282	282	3	(1,117,501)	UT	Situs	(1,117,501)	10.18.1
Current Tax Credits	40910	3	11,388,369	SG	43.997%	5,010,597	10.18.2

Description of Adjustment:

This adjustment normalizes base period schedule M, deferred tax expense, and accumulated deferred income tax balances to an estimated pro forma level for the CY December 2021 test period. The rebuttal filing includes an incremental change to reflect the impacts of a 481(a) adjustment related to bonus depreciation that was filed with the 2019 tax return. This adjustment also incorporates changes to PTCs as a result of the delayed in-service for Pryor Mountain and TB Flats.

Rocky Mountain Power
Utah General Rate Case - December 2021
Pro-Forma Tax Update

	ACCOUNT	Type	AS FILED TOTAL COMPANY	INCREMENTAL TOTAL COMPANY	REBUTTAL TOTAL COMPANY	FACTOR	REF#
Adjustment to Tax:							
ADIT Balance 190	190	3	234,702	-	234,702	BADDEBT	
	190	3	(540,134)	-	(540,134)	CA	
	190	3	(2,430,679)	-	(2,430,679)	IDU	
	190	3	(12,418,487)	-	(12,418,487)	OR	
	190	3	5,609,284	-	5,609,284	OTHER	
	190	3	(343,142)	-	(343,142)	SE	
	190	3	(24,730,077)	-	(24,730,077)	SG	
	190	3	(24,406,866)	-	(24,406,866)	SO	
	190	3	(6,026)	-	(6,026)	TROJD	
	190	3	62,928	-	62,928	UT	
	190	3	(305,045)	-	(305,045)	WA	
	190	3	(5,307,987)	-	(5,307,987)	WYP	
	190	3	553,745	-	553,745	SNPD	
	190	3	1,050,750	-	1,050,750	WYU	
	190	3	(4,001)	-	(4,001)	FERC	
			(62,981,035)	-	(62,981,035)		
ADIT Balance 281	281	3	177,382,631	-	177,382,631	SG	
ADIT Balance 282	282	3	(91,111,232)	-	(91,111,232)	CA	
	282	3	3,886,209,064	-	3,886,209,064	DITBAL	
	282	3	(249,302,194)	-	(249,302,194)	IDU	
	282	3	(951,736,235)	-	(951,736,235)	OR	
	282	3	(55,297,623)	-	(55,297,623)	OTHER	
	282	3	(73,758)	-	(73,758)	SE	
	282	3	659,834	-	659,834	SG	
	282	3	(34,210)	-	(34,210)	SO	
	282	3	(1,884,715,724)	(1,117,501)	(1,885,833,225)	UT	
	282	3	(265,312,532)	-	(265,312,532)	WA	
	282	3	(610,220,515)	-	(610,220,515)	WYP	
	282	3	(6,620,664)	-	(6,620,664)	FERC	
			(227,555,790)	(1,117,501)	(228,673,291)		
ADIT Balance 283	283	3	(1,067,151)	-	(1,067,151)	CA	
	283	3	748	-	748	GPS	
	283	3	145,748	-	145,748	IDU	
	283	3	(843,292)	-	(843,292)	OR	
	283	3	(45,863,172)	-	(45,863,172)	OTHER	
	283	3	3,777,451	-	3,777,451	SE	
	283	3	329,390	-	329,390	SG	
	283	3	283,474	-	283,474	SNP	
	283	3	12,681,766	-	12,681,766	SO	
	283	3	(1,115,768)	-	(1,115,768)	UT	
	283	3	(380,542)	-	(380,542)	WA	
	283	3	312,544	-	312,544	WYP	
	283	3	199,023	-	199,023	WYU	
			(31,539,782)	-	(31,539,782)		
ADIT Balance 255	255	3	42,534	-	42,534	ITC90	
	255	3	23,387	-	23,387	SG	
	255	3	10,214	-	10,214	IDU	
			76,135	-	76,135		

Rocky Mountain Power
Utah General Rate Case - December 2021
Pro-Forma Tax Update

10.18.2

	ACCOUNT	Type	AS FILED TOTAL COMPANY	INCREMENTAL TOTAL COMPANY	REBUTTAL TOTAL COMPANY	FACTOR	REF#
Adjustment to Tax:							
Schedule M Adjustment Permanent	SCHMAP	3	(4,529)	-	(4,529)	SCHMDEXP	
	SCHMAP	3	(47,560)	-	(47,560)	SE	
	SCHMAP	3	180,832	-	180,832	SO	
			128,743	-	128,743		
	SCHMDP	3	(137,397)	-	(137,397)	SE	
			(137,397)	-	(137,397)		
Schedule M Adjustment Temporary	SCHMAT	3	(52,155)	-	(52,155)	BADDEBT	
	SCHMAT	3	2,187,116	-	2,187,116	CA	
	SCHMAT	3	(53,434,293)	-	(53,434,293)	CIAC	
	SCHMAT	3	1,736,838	-	1,736,838	GPS	
	SCHMAT	3	(132,560)	-	(132,560)	IDU	
	SCHMAT	3	5,748,219	-	5,748,219	OR	
	SCHMAT	3	(94,974,549)	-	(94,974,549)	OTHER	
	SCHMAT	3	197,969,861	-	197,969,861	SCHMDEXP	
	SCHMAT	3	(82,643,860)	-	(82,643,860)	SE	
	SCHMAT	3	7,047,194	-	7,047,194	SG	
	SCHMAT	3	(33,549,824)	-	(33,549,824)	SNP	
	SCHMAT	3	(2,372,063)	-	(2,372,063)	SNPD	
	SCHMAT	3	19,193,736	-	19,193,736	SO	
	SCHMAT	3	60,836	-	60,836	TROJD	
	SCHMAT	3	902,944	-	902,944	UT	
	SCHMAT	3	(11,442,253)	-	(11,442,253)	WA	
	SCHMAT	3	(674,303)	-	(674,303)	WYP	
	SCHMAT	3	(22,244)	-	(22,244)	WYU	
			(44,451,360)	-	(44,451,360)		
	SCHMDT	3	1,125,442	-	1,125,442	CA	
	SCHMDT	3	(43,269,853)	-	(43,269,853)	GPS	
	SCHMDT	3	1,545,508	-	1,545,508	IDU	
	SCHMDT	3	12,367,555	-	12,367,555	OR	
	SCHMDT	3	(76,811,754)	-	(76,811,754)	OTHER	
	SCHMDT	3	(95,224,491)	-	(95,224,491)	SE	
	SCHMDT	3	(13,928,790)	-	(13,928,790)	SG	
	SCHMDT	3	(37,844,237)	-	(37,844,237)	SNP	
	SCHMDT	3	1,021,518	-	1,021,518	SNPD	
	SCHMDT	3	(4,503,813)	-	(4,503,813)	SO	
	SCHMDT	3	827,977,182	-	827,977,182	TAXDEPR	
	SCHMDT	3	4,370,052	-	4,370,052	UT	
	SCHMDT	3	5,894,012	-	5,894,012	WA	
	SCHMDT	3	182,131	-	182,131	WYP	
	SCHMDT	3	2,479,660	-	2,479,660	WYU	
			585,380,123	-	585,380,123		
Current Tax Credits	40910	3	47,560	-	47,560	SE	
	40910	3	(165,674,079)	11,388,369	(154,285,710)	SG	
	40910	3	15,800	-	15,800	SO	
			(165,610,719)	11,388,369	(154,222,350)		

Rocky Mountain Power
Utah General Rate Case - December 2021
Production Tax Credit

Pro Forma Period - December 2021					
Description	**Total Available KWh**	**Repowering Date**	**Total PTC Eligible KWh**	**Factor (inflated tax per unit)**	**Federal Income Tax Credit**
Wind/Geothermal					
Glenrock KWh **[a]**	(371,354,368)	**9/24/2019**	(340,531,956)	0.025	(8,513,299)
Glenrock III KWh **[a]**	(136,970,049)	**11/24/2019**	(113,685,141)	0.025	(2,842,129)
Goodnoe KWh	(284,561,444)	**12/20/2019**	(284,561,444)	0.025	(7,114,036)
High Plains Wind	(381,845,267)	**12/19/2019**	(381,845,267)	0.025	(9,546,132)
Leaning Juniper 1 KWh	(299,841,979)	**9/13/2019**	(299,841,979)	0.025	(7,496,049)
Marengo KWh	(488,061,345)	**1/27/2020**	(488,061,345)	0.025	(12,201,534)
Marengo II KWh	(232,351,885)	**2/25/2020**	(232,351,885)	0.025	(5,808,797)
McFadden Ridge	(116,455,002)	**11/17/2019**	(116,455,002)	0.025	(2,911,375)
Rolling Hills KWh **[a]**	(320,425,732)	**10/17/2019**	(245,446,110)	0.025	(6,136,153)
Seven Mile KWh	(417,996,452)	**9/9/2019**	(417,996,452)	0.025	(10,449,911)
Seven Mile II KWh	(87,580,282)	**9/9/2019**	(87,580,282)	0.025	(2,189,507)
Dunlap I Wind KWh	(476,859,527)	10/15/2020	(476,859,527)	0.025	(11,921,488)
Foote Creek I Wind	(176,168,730)	12/1/2020	(176,168,730)	0.025	(4,404,218)
Pryor Mountain Wind **[b]**	(693,890,821)	12/31/2020	(693,890,821)	0.025	(17,347,271)
Cedar Springs Wind II	(749,501,075)	11/1/2020	(749,501,075)	0.025	(18,737,527)
Ekola Flats Wind	(819,429,663)	11/1/2020	(819,429,663)	0.025	(20,485,742)
TB Flats Wind	(847,123,795)	11/1/2020	(847,123,795)	0.025	(21,178,095)
TB Flats Wind II **[b]**	(511,797,856)	11/1/2020	(511,797,856)	0.025	(12,794,946)
Total KWh Production	(7,412,215,271)		(7,283,128,329)		(182,078,209)
Total Federal Production Tax Credit					(182,078,209)

Repowering In Service dates in **bold** reflect actual in-service dates.

[a] Total available Kwh is reflected net of the generation that is not considered PTC eligible because the facility was not fully repowered. For Glenrock, the disallowed Kwh represents 8.3% of the total. For Glenrock III, the disallowed Kwh represents 17% disallowed. For Rolling Hills, the disallowed KWh represents 23.4% disallowed.

[b] The rebuttal filing has been updated to reflect revised 2021 generation as a result of delayed in-service for Pryor Mountain and TB Flats II.

December 2019 Results of Operations PTC	(27,792,500)	
Proforma Adjustment	(154,285,709)	**Ref. 10.18.2**

Rocky Mountain Power
Utah General Rate Case - December 2021
Removal of TCJA Deferred Balances - Correction

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED	REF#
Adjustments to Rate Base:							
Reg Liab - Non-Protected PP&E EDIT - UT	254	1	3,568,513	UT	Situs	3,568,513	10.19.1

Description of Adjustment:

This incremental adjustment corrects the removal of the non-protected property EDIT regulatory liability.

Rocky Mountain Power
Utah General Rate Case - December 2021
Removal of TCJA Deferred Balances - Correction

		ORIGINAL FILING	REBUTTAL FILING	INCREMENTAL CHANGE	
SAP Account 288936 - Reg Liab Protected PP&E EDIT - UT - Prorated 12/31/2021 Balance - 13MA	**7.7.3**	(664,039,125)	(664,039,125)	0	
SAP Account 288936 - Reg Liab Protected PP&E EDIT - UT - Base Period 13MA	**7.7.2**	(55,443,306)	(55,443,306)	0	
Adjustment Needed		(608,595,819)	(608,595,819)	0	**Ref 10.19**
SAP Account 288944 - Reg Liab Protected PP&E EDIT Amort - 2021 Expected Balance	**NOTE 1**	0	0	0	
SAP Account 288944 - Reg Liab Protected PP&E EDIT Amort - UT - Base Period 13MA	**7.7.2**	(30,370,255)	(30,370,255)	0	
Adjustment Needed		30,370,255	30,370,255	0	**Ref 10.19**
SAP Account 288216 - Reg Liab Non-Protected PP&E EDIT - 2021 Expected Balance	**NOTE 1**	0	0	0	
SAP Account 288216 - Reg Liab Non-Protected PP&E EDIT - UT - Base Period 13MA	**7.7.2**	(3,619,919)	(7,188,432)	(3,568,513)	
Adjustment Needed		3,619,919	7,188,432	3,568,513	**Ref 10.19**
SAP Account 287116 - DTA RL Prot PP&E EDIT - UT - Prorated 12/31/2021 Balance - 13MA	**7.7.3**	163,264,645	163,264,645	0	
SAP Account 287116 - DTA RL Prot PP&E EDIT - UT - Base Period 13MA	**7.7.2**	13,631,624	13,631,624	0	
Adjustment Needed		149,633,021	149,633,021	0	**Ref 10.19**
SAP Account 287064 - DTA RL Prot PP&E EDIT Amort - UT - Expected 2021 Balance	**NOTE 1**	0	0	0	
SAP Account 287064 - DTA RL Prot PP&E EDIT Amort - UT - Base Period 13MA	**7.7.2**	7,467,013	7,467,013	0	
Adjustment Needed		(7,467,013)	(7,467,013)	0	**Ref 10.19**
					Ref 10.19
SAP Account 287126 - DTA RL Non-Prot PP&E EDIT - UT - Expected 2021 Balance	**NOTE 1**	0	0	0	
SAP Account 287126 - DTA RL Non-Prot PP&E EDIT - UT - Base Period 13MA	**7.7.2**	451,327	451,327	0	
Adjustment Needed		(451,327)	(451,327)	0	**Ref 10.19**
SAP Account 287607 - DTL PMI Fixed Assets - Protected PP&E EDIT - Prorated 12/31/2021 Balance - 13MA		(2,714,246)	(2,714,246)	0	
SAP Account 287607 - DTL PMI Fixed Assets - Protected PP&E EDIT - Base Period 13MA		(6,779,262)	(6,779,262)	0	
Adjustment Needed		4,065,016	4,065,016	0	**Ref 10.19**
PacifiCorp Only RSGM Amortization - Dec. 2021		(21,188,112)	(21,188,112)	0	
PMI Only ARAM Amortization - Dec. 2021		(606,435)	(606,435)	0	
Subtotal - Protected PP&E EDIT Amortization		(21,794,547)	(21,794,547)	0	
PacifiCorp Only ARAM/RSGM Amortization - per Base Period		0	0	0	**NOTE 2**
Difference - Adjustment needed		(21,794,547)	(21,794,547)	0	**Ref 10.19**

NOTE 1: These balances are being removed from rate base as it is being proposed in the current GRC that any remaining EDIT balances will be used to buydown plant balances.

NOTE 2: The proforma period EDIT amortization is the same as the base period - which is zero. The only amortization to be proposed as part of base rates is RSGM amortization. All other balances will be amortized via a separate tariff or rider.

Rocky Mountain Power
Utah General Rate Case - December 2021
Pro-Forma Plant Data Update

Adjustment to Rate Base:	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED	REF#
Steam Plant	312	3	(13,195,278)	SG	43.997%	(5,805,592)	10.20.2
Hydro Plant	332	3	(7,038,632)	SG-P	43.997%	(3,096,822)	10.20.2
Hydro Plant	332	3	(1,419,043)	SG-U	43.997%	(624,343)	10.20.2
Other Plant	343	3	68,330	SG	43.997%	30,063	10.20.2
Other Plant	343	3	(320,427,032)	SG-W	43.997%	(140,979,877)	10.20.2
Transmission Plant	355	3	(27,999,013)	SG	43.997%	(12,318,865)	10.20.2
Distribution Plant	360	3	(213,116)	UT	Situs	(220,527)	10.20.2
Distribution Plant	361	3	(407,030)	UT	Situs	(421,184)	
Distribution Plant	362	3	(3,421,491)	UT	Situs	(3,540,464)	
Distribution Plant	364	3	(4,126,007)	UT	Situs	(4,269,477)	
Distribution Plant	365	3	(2,622,731)	UT	Situs	(2,713,929)	
Distribution Plant	366	3	(1,302,719)	UT	Situs	(1,348,017)	
Distribution Plant	367	3	(3,045,740)	UT	Situs	(3,151,647)	
Distribution Plant	368	3	(4,684,991)	UT	Situs	(4,847,899)	
Distribution Plant	369	3	(2,805,004)	UT	Situs	(2,902,540)	
Distribution Plant	370	3	(790,878)	UT	Situs	(818,378)	
Distribution Plant	371	3	(29,430)	UT	Situs	(30,453)	
Distribution Plant	373	3	(209,413)	UT	Situs	(216,695)	10.20.2
General Plant	397	3	(80,466)	SG	43.997%	(35,403)	
General Plant	397	3	(927,692)	SO	43.595%	(404,425)	
General Plant	397	3	(29,248,655)	UT	Situs	(29,248,655)	
Intangible Plant:	303	3	(7,275,386)	SO	43.595%	(3,171,682)	10.20.2
			(431,201,416)			(214,331,219)	

Adjustment to Depreciation Expense:	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED	REF#
Steam Plant	403SP	3	(697,027)	SG	43.997%	(306,674)	10.20.2
Hydro Plant	403HP	3	(185,775)	SG-P	43.997%	(81,736)	10.20.2
Hydro Plant	403HP	3	(63,321)	SG-U	43.997%	(27,860)	10.20.2
Other Plant	403OP	3	2,395	SG	43.997%	1,054	10.20.2
Other Plant	403OP	3	(15,505,722)	SG-W	43.997%	(5,855)	10.20.2
Transmission Plant	403TP	3	(490,089)	SG	43.997%	(11,182)	10.20.2
Distribution Plant	403360	3	(5,663)	UT	Situs	(93,996)	10.20.2
Distribution Plant	403361	3	(10,816)	UT	Situs	(113,351)	
Distribution Plant	403362	3	(90,918)	UT	Situs	(72,052)	
Distribution Plant	403364	3	(109,639)	UT	Situs	(35,789)	
Distribution Plant	403365	3	(69,693)	UT	Situs	(83,673)	
Distribution Plant	403366	3	(34,617)	UT	Situs	(128,707)	
Distribution Plant	403367	3	(80,933)	UT	Situs	(77,060)	
Distribution Plant	403368	3	(124,492)	UT	Situs	(21,727)	
Distribution Plant	403369	3	(74,536)	UT	Situs	(809)	
Distribution Plant	403370	3	(21,016)	UT	Situs	(5,753)	
Distribution Plant	403371	3	(782)	UT	Situs	(782)	
Distribution Plant	403373	3	(5,565)	UT	Situs	(5,565)	10.20.2
General Plant	403GP	3	(1,500)	SG	43.997%	(660)	
General Plant	403GP	3	(46,418)	SO	43.595%	(20,236)	
General Plant	403GP	3	(698,850)	UT	Situs	(698,850)	
Intangible Plant:	404IP	3	(335,664)	SO	43.595%	(146,332)	10.20.2
			(18,650,639)			(18,650,639)	

Description of Adjustment:

This incremental adjustment incorporates updates to the Test Year capital additions proposed by Mr. Higgins as provided in the data request response UAE 3.9 1st Revised. The incremental change to Nodal Pricing is included in 10.14. The UT AMI project is removed as filed and updated with the current project costs. This adjustment also updates the new projects identified in UAE 3.9 1st Revised and other projects found during the preparation of the rebuttal filing. Also, this incremental adjustment captures the updated in-service dates for the new wind projects.

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Utah General Rate Case - December 2021
Pro-Forma Plant Data Update

Adjustment to Depreciation Reserve:	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED	REF#
Steam Plant	108SP	3	228,992	SG	43.997%	100,751	10.20.2
Hydro Plant	108HP	3	80,216	SG-P	43.997%	35,293	10.20.2
Hydro Plant	108HP	3	11,133	SG-U	43.997%	4,898	10.20.2
Other Plant	108OP	3	17,969	SG	43.997%	7,906	10.20.2
Other Plant	108OP	3	5,475,560	SG-W	43.997%	2,409,110	10.20.2
Transmission Plant	108TP	3	363,411	SG	43.997%	159,892	10.20.2
Distribution Plant	108360	3	4,104	UT	Situs	4,238	10.20.2
Distribution Plant	108361	3	7,839	UT	Situs	8,094	
Distribution Plant	108362	3	65,894	UT	Situs	68,037	
Distribution Plant	108364	3	79,462	UT	Situs	82,046	
Distribution Plant	108365	3	50,511	UT	Situs	52,153	
Distribution Plant	108366	3	25,089	UT	Situs	25,905	
Distribution Plant	108367	3	58,657	UT	Situs	60,565	
Distribution Plant	108368	3	90,227	UT	Situs	93,162	
Distribution Plant	108369	3	54,021	UT	Situs	55,778	
Distribution Plant	108370	3	15,231	UT	Situs	15,727	
Distribution Plant	108371	3	567	UT	Situs	585	
Distribution Plant	108373	3	4,033	UT	Situs	4,164	10.20.2
General Plant	108GP	3	115	SG	43.997%	51	
General Plant	108GP	3	25,297	SO	43.595%	11,028	
General Plant	108GP	3	362,924	UT	Situs	362,924	
Intangible Plant:	111IP	3	208,573	SO	43.595%	90,927	10.20.2
			7,229,826			3,552,482	
Adjustment to O&M:							
Incremental Wind O&M Expense	549	3	(2,535,501)	SG	43.997%	(1,115,557)	10.20.2
Adjustment to Tax:							
Schedule M Addition - SG - 2021 Book Depr	SCHMAT	3	(16,941,039)	SG	43.997%	(7,453,633)	
Schedule M Addition - SO - 2021 Book Depr	SCHMAT	3	(382,081)	SO	43.595%	(166,567)	
Schedule M Addition - UT - 2021 Book Depr	SCHMAT	3	(1,348,803)	UT	Situs	(1,348,803)	
Schedule M Addition - OR - 2021 Book Depr	SCHMAT	3	21,285	OR	Situs	-	
			(18,650,639)				
Schedule M Deduction - SG	SCHMDT	3	(105,994,971)	SG	43.997%	(46,635,135)	
Schedule M Deduction - SO	SCHMDT	3	(3,039,763)	SO	43.595%	(1,325,175)	
Schedule M Deduction - UT	SCHMDT	3	(5,608,022)	UT	Situs	(5,608,022)	
Schedule M Deduction - OR	SCHMDT	3	59,388	OR	Situs	-	
			(114,583,368)				
Deferred Inc Tax Exp - SG - 2021 Book Depr	41110	3	4,165,226	SG	43.997%	1,832,595	
Deferred Inc Tax Exp - SO - 2021 Book Depr	41110	3	93,941	SO	43.595%	40,953	
Deferred Inc Tax Exp - UT - 2021 Book Depr	41110	3	331,625	UT	Situs	331,625	
Deferred Inc Tax Exp - OR - 2021 Book Depr	41110	3	(5,233)	OR	Situs	-	
			4,585,559				
Deferred Inc Tax Exp - SG - 2021 Book Depr	41010	3	(26,094,987)	SG	43.997%	(11,481,141)	
Deferred Inc Tax Exp - SO - 2021 Book Depr	41010	3	(747,374)	SO	43.595%	(325,815)	
Deferred Inc Tax Exp - UT - 2021 Book Depr	41010	3	(1,378,822)	UT	Situs	(1,378,822)	
Deferred Inc Tax Exp - OR - 2021 Book Depr	41010	3	14,601	OR	Situs	-	
			(28,206,582)				
ADIT - SG	282	3	39,959,937	SG	43.997%	17,581,373	
ADIT - SO	282	3	552,954	SO	43.595%	241,059	
ADIT - UT	282	3	1,904,838	UT	Situs	1,904,838	
ADIT - OR	282	3	(9,435)	OR	Situs	-	
			42,408,294				

Description of Adjustment:

This incremental adjustment incorporates updates to the Test Year capital additions proposed by Mr. Higgins as provided in the data request response UAE 3.9 1st Revised. The incremental change to Nodal Pricing is included in 10.14. The UT AMI project is removed as filed and updated with the current project costs. This adjustment also updates the new projects identified in UAE 3.9 1st Revised and other projects found during the preparation of the rebuttal filing. Also, this incremental adjustment captures the updated in-service dates for the new wind projects.

Rocky Mountain Power
Utah General Rate Case - December 2021
Pro Forma Plant Data Update

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	ACCOUNT	Type	Factor	AS FILED TOTAL COMPANY	INCREMENTAL TOTAL COMPANY	REBUTTAL TOTAL COMPANY	REF#
Adjustment to Rate Base:							
Steam Plant	312	3	SG	123,052,380	(13,195,278)	109,857,102	10.20.3
Hydro Plant	332	3	SG-P	62,075,508	(7,038,632)	55,036,876	10.20.3
Hydro Plant	332	3	SG-U	8,085,561	(1,419,043)	6,666,518	10.20.3
Other Plant	343	3	SG	42,219,283	68,330	42,287,613	10.20.3
Other Plant	343	3	SG-W	1,626,887,690	-	1,626,887,690	10.20.3
Transmission Plant	355	3	SG	450,529,111	(27,999,013)	422,530,098	10.20.3
Distribution Plant - OR	360-373	3	OR	197,089,839	822,662	197,912,500	10.20.4
Distribution Plant - UT	360-373	3	UT	354,777,819	(24,481,210)	330,296,608	10.20.4
General Plant	397	3	SG	16,995,839	(80,466)	16,915,373	10.20.4
General Plant	397	3	SO	23,028,354	(927,692)	22,100,661	10.20.4
General Plant	397	3	UT	57,029,857	(29,248,655)	27,781,203	10.20.4
Intangible Plant:	303	3	SO	30,658,747	(7,275,386)	23,383,361	10.20.4
Remaining Plant same as Filed				380,171,835	-	380,171,835	
				3,372,601,821	(110,774,384)	3,261,827,438	
Adjustment to Depreciation Expense:							
Steam Plant	403SP	3	SG	93,102,794	(697,027)	92,405,767	10.20.5
Hydro Plant	403HP	3	SG-P	(34,227,856)	(185,775)	(34,413,632)	10.20.5
Hydro Plant	403HP	3	SG-U	1,206,498	(63,321)	1,143,177	10.20.5
Other Plant	403OP	3	SG	11,049,672	2,395	11,052,067	10.20.5
Other Plant	403OP	3	SG-W	78,714,795	-	78,714,795	10.20.5
Transmission Plant	403TP	3	SG	6,249,355	(490,089)	5,759,266	10.20.5
Distribution Plant - OR	360-373	3	OR	6,281,792	21,285	6,303,077	10.20.6
Distribution Plant - UT	360-373	3	UT	30,001,728	(649,953)	29,351,775	10.20.6
General Plant	403GP	3	SG	584,529	(1,500)	583,028	10.20.6
General Plant	403GP	3	SO	3,357,889	(46,418)	3,311,471	10.20.6
General Plant	403GP	3	UT	1,739,554	(698,850)	1,040,704	10.20.6
Intangible Plant:	404IP	3	SO	8,588,243	(335,664)	8,252,580	10.20.6
Remaining Plant same as Filed				47,509,435	-	47,509,435	
				254,158,427	(3,144,917)	251,013,510	
Adjustment to Depreciation Reserve:							
Steam Plant	108SP	3	SG	(264,376,144)	228,992	(264,147,152)	10.20.7
Hydro Plant	108HP	3	SG-P	(66,194,693)	80,216	(66,114,477)	10.20.7
Hydro Plant	108HP	3	SG-U	(10,596,652)	11,133	(10,585,519)	10.20.7
Other Plant	108OP	3	SG	(80,501,490)	17,969	(80,483,521)	10.20.7
Other Plant	108OP	3	SG-W	(41,592,853)	-	(41,592,853)	10.20.7
Transmission Plant	108TP	3	SG	(157,000,008)	363,411	(156,636,597)	10.20.7
Distribution Plant - OR	360-373	3	OR	(56,215,788)	(14,818)	(56,230,606)	10.20.8
Distribution Plant - UT	360-373	3	UT	(103,210,671)	470,454	(102,740,217)	10.20.8
General Plant	108GP	3	SG	(17,083,184)	115	(17,083,068)	10.20.8
General Plant	108GP	3	SO	(3,340,908)	25,297	(3,315,612)	10.20.8
General Plant	108GP	3	UT	(10,816,972)	362,924	(10,454,048)	10.20.8
Intangible Plant:	111IP	3	SO	(52,924,450)	208,573	(52,715,877)	10.20.8
Remaining Plant same as Filed				793,713,891	-	793,713,891	
				(70,139,922)	1,754,266	(68,385,657)	
Adjustment to Operations & Maintenance Expense:							
Incremental Wind O&M Expense	549	SG		19,937,139	(2,535,501)	17,401,638	

Rocky Mountain Power
Utah General Rate Case - December 2021
Pro Forma Plant Data Update
REDACTED

Project Description	Notes	FERC Account	Factor	In-Service	Jan 2020 - Dec 2021 Plant Additions	December 2021 13 Month Avg
Steam Production						
Hunter 303 CCR Forced Oxidation Project	UAE 3.9	312	SG	Jun-21	(13,322,397)	(7,173,599)
Naughton U1 OH Turbine Major (HP/IP/LP) CY21	UAE 3.9	312	SG	Dec-21	(3,496,635)	(268,972)
Wyodak U1 - Boiler Waterwall Replacement CY20/CY21	UAE 3.9	312	SG	May-21	(3,041,969)	(1,871,981)
Craig CRGU5 RELIABILITY/ABILITY TO SERVE CY20	UAE 3.9	312	SG	Dec-20	(1,907,860)	(1,907,860)
Craig CRGU0 NEW COAL STORAGE SILOS CY21	UAE 3.9	312	SG	Dec-21	(1,870,321)	(143,871)
Jim Bridger U2 Burners Major 21	UAE 3.9	312	SG	Jun-21	(1,786,957)	(962,208)
Craig CRGU5 REGULATORY ENVIRON & SAFETY CY20	UAE 3.9	312	SG	Dec-20	(1,483,898)	(1,483,898)
Wyodak U1 - Ovation Major Upgrade CY21	UAE 3.9	312	SG	May-21	(1,480,209)	(910,898)
Colstrip COLU5 CCR-CONSTRUCt DRY WASTE DISPOSAL CY21 TUCK	UAE 3.9	312	SG	Dec-21	(1,164,537)	(89,580)
Wyodak U1 - Pulverizer Overhaul "A" CY21	UAE 3.9	312	SG	Apr-21	(1,147,696)	(794,559)
Wyodak U1 - Scrubber 'A' Chamber Reinforcement CY19/CY20	UAE 3.9	312	SG	May-21	(1,017,139)	(625,932)
Wyodak U1 - Pulverizer Overhaul "C" CY21	UAE 3.9 New Capital Additions	312	SG	Dec-21	1,129,014	173,694
Wyodak U1 - Pulverizer Overhaul "D" CY21	UAE 3.9 New Capital Additions	312	SG	Oct-20	1,131,914	1,131,914
Naughton U2 OH Mechanical Dust Collectors CY20	UAE 3.9 New Capital Additions	312	SG	May-21	1,373,272	845,090
Naughton U2 OH Boiler: Header Replacement CY20	UAE 3.9 New Capital Additions	312	SG	May-21	1,441,992	887,380
Steam Production Total					**(26,643,427)**	**(13,195,278)**
Hydro Production Plant						
Soda Spinning Reserve	UAE 3.9	332	SG-U	Sep-21	(4,611,888)	(1,419,043)
Swift 1 Spillway Gate Bulkhead	UAE 3.9	332	SG-P	Jun-21	(4,374,266)	(2,355,374)
Toketee Dam Rehabilitation Evaluation	UAE 3.9	332	SG-P	Dec-21	(3,524,437)	(271,111)
Swift 1 Spillway Gate Retrofit	UAE 3.9	332	SG-P	Oct-21	(3,030,460)	(699,337)
Swift 1 Minimum Discharge Line	UAE 3.9	332	SG-P	Nov-20	(2,286,463)	(2,286,463)
Bull Trout Yale Downstream Facility	UAE 3.9	332	SG-P	Nov-21	(1,706,528)	(262,543)
Yale Spillway Gate Improvements	UAE 3.9	332	SG-P	Dec-21	(1,566,440)	(120,495)
ILR 4.4.1 Swift FSC NTS Upgrade Phase 2	UAE 3.9	332	SG-P	Dec-21	(1,370,909)	(105,455)
Eastside Flowline Removal	UAE 3.9	332	SG-P	Nov-20	(1,122,005)	(1,122,005)
ILR 4.4.1 Swift FSC Attract Pump DM Mod	UAE 3.9	332	SG-P	Dec-21	(1,085,303)	(83,485)
Yale Saddle Dam Seismic Remediation	UAE 3.9 New Capital Additions	332	SG-P	Nov-21	1,739,624	267,634
					(22,939,075)	**(8,457,675)**
Other Production						
Lakeside Blk 1 U12 Generator Rotor Replacement	UAE 3.9	343	SG	Apr-20	(2,095,411)	(2,095,411)
Hermiston U1 - OH - Stator/Generator rewind	UAE 3.9 New Capital Additions	343	SG	Dec-20	1,048,229	1,048,229
Currant Creek U3 ST Diaphragm Replacement	UAE 3.9 New Capital Additions	343	SG	Apr-20	1,115,512	1,115,512
Cedar Springs Wind Project 200 MW 2020	Remove as Filed	343	SG-W	Dec-20	[redacted]	[redacted]
Cedar Springs Wind Project 200 MW 2020	Remove as Filed	343	SG-W	Dec-20	[redacted]	[redacted]
Ekola Flats Wind Project 250 MW 2020	Remove as Filed	343	SG-W	Dec-20	[redacted]	[redacted]
TB Flats Wind Project 500 MW 2020	Remove as Filed	343	SG-W	Dec-20	[redacted]	[redacted]
Pryor Mtn Wind Project 240 MW 2020	Remove as Filed	343	SG-W	Dec-20	[redacted]	[redacted]
Cedar Springs Wind Project 200 MW 2020	Update Project Data	343	SG-W	Nov-20	[redacted]	[redacted]
Ekola Flats Wind Project 250 MW 2020	Update Project Data	343	SG-W	Various	[redacted]	[redacted]
TB Flats Wind Project 500 MW 2020	Update Project Data	343	SG-W	Various	[redacted]	[redacted]
Pryor Mtn Wind Project 240 MW 2020	Update Project Data	343	SG-W	Various	[redacted]	[redacted]
Other Production Total					**(320,529,085)**	**(320,358,703)**
Transmission						
TMP Transmission Major Projects - PP (Flint New 115kV to 12.5kV Substation)	UAE 3.9	355	SG	Various	(13,280,307)	(8,952,833)
TMP Trans Main Grid West (Shevlin Park Substation Increase Capacity)	UAE 3.9	355	SG	Various	(6,297,100)	(2,045,950)
Blue Creek - Bothwell Tap 46 kV Reconductor/Rebuild	UAE 3.9 New Capital Additions	355	SG	May-21	1,986,400	1,222,400
Southeast - Install New Control Building	UAE 3.9 New Capital Additions	355	SG	Dec-21	1,017,500	78,269
Spare 230-161kV 150 MVA Xfmr	UAE 3.9 New Capital Additions	355	SG	Sep-21	1,000,000	307,692
UDOT I-15 NB; Bangerter Hwy to I-215	UAE 3.9 New Capital Additions	355	SG	Oct-20	2,256,384	2,256,384
Tyson Foods, 8 MW	UAE 3.9 New Capital Additions	355	SG	Dec-20	1,473,800	1,473,800
El Monte Substation Expansion	UAE 3.9 New Capital Additions	355	SG	Mar-20	2,642,587	2,642,587
Wildfire Mitigation - Trans	Remove as Filed	355	SG	Various	(41,679,625)	(29,766,265)
Wildfire Mitigation - Trans	Update Project Data	355	SG	Various	35,689,188	22,659,323
Pavant Transformer Protection	Remove as Filed	355	SG	Dec-20	(1,819,906)	(1,819,906)
Jordanelle - Midway Construct 138 kV Line	Remove as Filed	355	SG	Nov-20	(18,287,278)	(18,287,278)
Reroute JB Goshen 345kV line	Remove as Filed	355	SG	Oct-20	(1,959,432)	(1,959,432)
Parowan Valley Reg Replacement	Remove as Filed	355	SG	Dec-20	(969,907)	(969,907)
Block 216 Tower Service Request	Remove as Filed	355	SG	Oct-20	(822,662)	(822,662)
Pavant Transformer Protection	Update Project Data	355	SG	Dec-20	1,312,413	1,312,413
Jordanelle - Midway Construct 138 kV Line	Update Project Data	355	SG	Nov-21	25,213,948	3,879,069
Reroute JB Goshen 345kV line	Update Project Data	355	SG	Oct-21	3,437,559	793,283
Total Transmission					**(9,086,438)**	**(27,999,013)**

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Project Description	Notes	FERC Account	Factor	In-Service	Jan 2020 - Dec 2021 Plant Additions	December 2021 13 Month Avg
Distribution						
AMI - Utah Meters 2019 -2020	Remove as Filed	360-373	UT	Dec-20	(31,361,536)	(18,269,716)
AMI - Utah Meters - 2021	Update Project Data	360-373	UT	Various	24,106,000	4,885,231
Wildfire Mitigation - Dist	Remove as Filed	360-373	UT	Various	(54,435,875)	(42,571,042)
Wildfire Mitigation - Dist	Update Project Data	360-373	UT	Various	39,295,020	28,391,368
Timp Install New 12kV Transformer	UAE 3.9	360-373	UT	May-21	(6,312,581)	(3,884,665)
Healthy Mountain Farms LLC, 5 MW New Load - Phase 1	UAE 3.9 New Capital Additions	360-373	UT	Oct-21	3,575,331	825,076
WPR Development Company, 18.725 MW	UAE 3.9 New Capital Additions	360-373	UT	Nov-21	5,442,426	837,296
Temple Square - 1.58 MW load addn in Downtown SLC	UAE 3.9 New Capital Additions	360-373	UT	Oct-21	1,521,753	351,174
118th S 6400 W Substation Property Acquisition	UAE 3.9 New Capital Additions	360-373	UT	Jul-21	2,085,000	962,308
Pony Express Enable Mobile Installation	UAE 3.9 New Capital Additions	360-373	UT	May-21	1,000,000	615,385
Terminal: Const T&D Training Facility	UAE 3.9 New Capital Additions	360-373	UT	Aug-20	2,406,469	2,406,469
Parowan Valley Reg Replacement	Update Project Data	360-373	UT	Dec-20	969,907	969,907
Block 216 Tower Service Request	Update Project Data	360-373	OR	Oct-20	822,662	822,662
Total Distribution					**(10,885,423)**	**(23,658,549)**
General						
AMI - Utah IT Comm Network	Remove as Filed	397	UT	Dec-20	(45,614,453)	(40,885,713)
AMI - Utah IT Comm Network	Update Project Data	397	UT	Dec-20	25,066,655	7,564,348
Wildfire Mitigation - General	Update Project Data	397	UT	Various	3,411,172	3,411,172
Field Ai	UAE 3.9	397	SO	Dec-21	(1,900,000)	(146,154)
Microsoft Office Upgrade	UAE 3.9	397	SO	Various	(1,520,000)	(781,538)
Vernal to Antelope diversity loop	UAE 3.9	397	SG	Dec-21	(1,046,063)	(80,466)
Electric Vehicle Infrastructure (HB 396)	UAE 3.9 New Capital Additions	397	UT	Various	8,600,000	661,538
Total General					**(13,002,688)**	**(30,256,814)**
Intangible						
Field Ai	UAE 3.9	303	SO	Dec-21	(7,600,000)	(584,615)
WEST	UAE 3.9	303	SO	Dec-20	(4,000,000)	(4,000,000)
AMI Headend- SSN/Itron Conversion	UAE 3.9	303	SO	Dec-21	(2,107,235)	(162,095)
Large Customer microsite	UAE 3.9	303	SO	Dec-21	(1,200,000)	(92,308)
Replace PAR/SO - Integrated Resource Plan (IRP) software	UAE 3.9	303	SO	Jul-20	(1,200,000)	(1,200,000)
Landlord microsite	UAE 3.9	303	SO	Dec-20	(1,200,000)	(1,200,000)
SMS check balance , pay bill	UAE 3.9	303	SO	Dec-20	(1,120,000)	(1,120,000)
Hortonworks SW	UAE 3.9 New Capital Additions	303	SO	Jun-21	1,315,800	708,508
Vegetation Management (PVM/Mobile)	UAE 3.9 New Capital Additions	303	SO	Dec-21	2,193,000	168,692
Compass Replacement	UAE 3.9 New Capital Additions	303	SO	Dec-21	2,683,620	206,432
					(12,234,815)	**(7,275,386)**
					(415,320,952)	**(431,201,416)**

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Project Description	Notes	FERC Account	Factor	In-Service	Jan 2021 - Dec 2021 Depreciation Expense
Steam Production					
Hunter 303 CCR Forced Oxidation Project	UAE 3.9	403SP	SG	Jun-21	(384,242)
Naughton U1 OH Turbine Major (HP/IP/LP) CY21	UAE 3.9	403SP	SG	Dec-21	(7,758)
Wyodak U1 - Boiler Waterwall Replacement CY20/CY21	UAE 3.9	403SP	SG	May-21	(101,234)
Craig CRGU5 RELIABILITY/ABILITY TO SERVE CY20	UAE 3.9	403SP	SG	Dec-20	(101,587)
Craig CRGU0 NEW COAL STORAGE SILOS CY21	UAE 3.9	403SP	SG	Dec-21	(4,149)
Jim Bridger U2 Burners Major 21	UAE 3.9	403SP	SG	Jun-21	(51,539)
Craig CRGU5 REGULATORY ENVIRON & SAFETY CY20	UAE 3.9	403SP	SG	Dec-20	(79,012)
Wyodak U1 - Ovation Major Upgrade CY21	UAE 3.9	403SP	SG	May-21	(49,260)
Colstrip COLU5 CCR-CONSTRUCt DRY WASTE DISPOSAL CY21 TUCK	UAE 3.9	403SP	SG	Dec-21	(2,584)
Wyodak U1 - Pulverizer Overhaul "A" CY21	UAE 3.9	403SP	SG	Apr-21	(43,287)
Wyodak U1 - Scrubber 'A' Chamber Reinforcement CY19/CY20	UAE 3.9	403SP	SG	May-21	(33,849)
Wyodak U1 - Pulverizer Overhaul "C" CY21	UAE 3.9 New Capital Additions	403SP	SG	Dec-21	7,514
Wyodak U1 - Pulverizer Overhaul "D" CY21	UAE 3.9 New Capital Additions	403SP	SG	Oct-20	60,270
Naughton U2 OH Mechanical Dust Collectors CY20	UAE 3.9 New Capital Additions	403SP	SG	May-21	45,701
Naughton U2 OH Boiler: Header Replacement CY20	UAE 3.9 New Capital Additions	403SP	SG	May-21	47,988
Steam Production Total					**(697,027)**
Hydro Production Plant					
Soda Spinning Reserve	UAE 3.9	403HP	SG-U	Sep-21	(63,321)
Swift 1 Spillway Gate Bulkhead	UAE 3.9	403HP	SG-P	Jun-21	(65,507)
Toketee Dam Rehabilitation Evaluation	UAE 3.9	403HP	SG-P	Dec-21	(4,060)
Swift 1 Spillway Gate Retrofit	UAE 3.9	403HP	SG-P	Oct-21	(17,455)
Swift 1 Minimum Discharge Line	UAE 3.9	403HP	SG-P	Nov-20	(63,214)
Bull Trout Yale Downstream Facility	UAE 3.9	403HP	SG-P	Nov-21	(5,898)
Yale Spillway Gate Improvements	UAE 3.9	403HP	SG-P	Dec-21	(1,804)
ILR 4.4.1 Swift FSC NTS Upgrade Phase 2	UAE 3.9	403HP	SG-P	Dec-21	(1,579)
Eastside Flowline Removal	UAE 3.9	403HP	SG-P	Nov-20	(31,020)
ILR 4.4.1 Swift FSC Attract Pump DM Mod	UAE 3.9	403HP	SG-P	Dec-21	(1,250)
Yale Saddle Dam Seismic Remediation	UAE 3.9 New Capital Additions	403HP	SG-P	Nov-21	6,012
					(249,096)
Other Production					
Lakeside Blk 1 U12 Generator Rotor Replacement	UAE 3.9	403OP	SG	Apr-20	(73,461)
Hermiston U1 - OH - Stator/Generator rewind	UAE 3.9 New Capital Additions	403OP	SG	Dec-20	36,749
Currant Creek U3 ST Diaphragm Replacement	UAE 3.9 New Capital Additions	403OP	SG	Apr-20	39,108
Cedar Springs Wind Project 200 MW 2020	Remove as Filed	403OP	SG-W	Dec-20	[redacted]
Cedar Springs Wind Project 200 MW 2020	Remove as Filed	403OP	SG-W	Dec-20	[redacted]
Ekola Flats Wind Project 250 MW 2020	Remove as Filed	403OP	SG-W	Dec-20	[redacted]
TB Flats Wind Project 500 MW 2020	Remove as Filed	403OP	SG-W	Dec-20	[redacted]
Pryor Mtn Wind Project 240 MW 2020	Remove as Filed	403OP	SG-W	Dec-20	[redacted]
Cedar Springs Wind Project 200 MW 2020	Update Project Data	403OP	SG-W	Nov-20	[redacted]
Ekola Flats Wind Project 250 MW 2020	Update Project Data	403OP	SG-W	Various	[redacted]
TB Flats Wind Project 500 MW 2020	Update Project Data	403OP	SG-W	Various	[redacted]
Pryor Mtn Wind Project 240 MW 2020	Update Project Data	403OP	SG-W	Various	[redacted]
Other Production Total					**(15,503,327)**
Transmission					
TMP Transmission Major Projects - PP (Flint New 115kV to 12.5kV Substation)	UAE 3.9	403TP	SG	Various	(151,089)
TMP Trans Main Grid West (Shevlin Park Substation Increase Capacity)	UAE 3.9	403TP	SG	Various	(32,385)
Blue Creek - Bothwell Tap 46 kV Reconductor/Rebuild	UAE 3.9 New Capital Additions	403TP	SG	May-21	21,346
Southeast - Install New Control Building	UAE 3.9 New Capital Additions	403TP	SG	Dec-21	729
Spare 230-161kV 150 MVA Xfmr	UAE 3.9 New Capital Additions	403TP	SG	Sep-21	5,015
UDOT I-15 NB; Bangerter Hwy to I-215	UAE 3.9 New Capital Additions	403TP	SG	Oct-20	38,795
Tyson Foods, 8 MW	UAE 3.9 New Capital Additions	403TP	SG	Dec-20	25,340
El Monte Substation Expansion	UAE 3.9 New Capital Additions	403TP	SG	Mar-20	45,436
Wildfire Mitigation - Trans	Remove as Filed	403TP	SG	Various	(512,615)
Wildfire Mitigation - Trans	Update Project Data	403TP	SG	Various	390,497
Pavant Transformer Protection	Remove as Filed	403TP	SG	Dec-20	(31,291)
Jordanelle - Midway Construct 138 kV Line	Remove as Filed	403TP	SG	Nov-20	(314,424)
Reroute JB Goshen 345kV line	Remove as Filed	403TP	SG	Oct-20	(33,690)
Parowan Valley Reg Replacement	Remove as Filed	403TP	SG	Dec-20	(16,676)
Block 216 Tower Service Request	Remove as Filed	403TP	SG	Oct-20	(14,144)
Pavant Transformer Protection	Update Project Data	403TP	SG	Dec-20	22,565
Jordanelle - Midway Construct 138 kV Line	Update Project Data	403TP	SG	Nov-21	54,190
Reroute JB Goshen 345kV line	Update Project Data	403TP	SG	Oct-21	12,313
Total Transmission					**(490,089)**

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Project Description	Notes	FERC Account	Factor	In-Service	Jan 2021 - Dec 2021 Depreciation Expense
Distribution					
AMI - Utah Meters 2019 -2020	Remove as Filed	403364	UT	Dec-20	(468,506)
AMI - Utah Meters - 2021	Update Project Data	403364	UT	Various	108,947
Wildfire Mitigation - Dist	Remove as Filed	403364	UT	Various	(1,082,858)
Wildfire Mitigation - Dist	Update Project Data	403364	UT	Various	722,495
Timp Install New 12kV Transformer	UAE 3.9	403364	UT	May-21	(100,244)
Healthy Mountain Farms LLC, 5 MW New Load - Phase 1	UAE 3.9 New Capital Additions	403364	UT	Oct-21	18,925
WPR Development Company, 18.725 MW	UAE 3.9 New Capital Additions	403364	UT	Nov-21	17,285
Temple Square - 1.58 MW load addn in Downtown SLC	UAE 3.9 New Capital Additions	403364	UT	Oct-21	8,055
118th S 6400 W Substation Property Acquisition	UAE 3.9 New Capital Additions	403364	UT	Jul-21	24,280
Pony Express Enable Mobile Installation	UAE 3.9 New Capital Additions	403364	UT	May-21	15,880
Terminal: Const T&D Training Facility	UAE 3.9 New Capital Additions	403364	UT	Aug-20	61,143
Parowan Valley Reg Replacement	Update Project Data	403364	UT	Dec-20	24,643
Block 216 Tower Service Request	Update Project Data	403364	OR	Oct-20	21,285
Total Distribution					**(628,668)**
General					
AMI - Utah IT Comm Network	Remove as Filed	403GP	UT	Dec-20	(948,770)
AMI - Utah IT Comm Network	Update Project Data	403GP	UT	Dec-20	162,862
Wildfire Mitigation - General	Update Project Data	403GP	UT	Various	78,782
Field Ai	UAE 3.9	403GP	SO	Dec-21	(4,414)
Microsoft Office Upgrade	UAE 3.9	403GP	SO	Various	(42,004)
Vernal to Antelope diversity loop	UAE 3.9	403GP	SG	Dec-21	(1,500)
Electric Vehicle Infrastructure (HB 396)	UAE 3.9 New Capital Additions	403GP	UT	Various	8,276
Total General					**(746,769)**
Intangible					
Field Ai	UAE 3.9	404IP	SO	Dec-21	(15,059)
WEST	UAE 3.9	404IP	SO	Dec-20	(190,217)
AMI Headend- SSN/Itron Conversion	UAE 3.9	404IP	SO	Dec-21	(4,175)
Large Customer microsite	UAE 3.9	404IP	SO	Dec-21	(2,378)
Replace PAR/SO - Integrated Resource Plan (IRP) software	UAE 3.9	404IP	SO	Jul-20	(57,065)
Landlord microsite	UAE 3.9	404IP	SO	Dec-20	(57,065)
SMS check balance , pay bill	UAE 3.9	404IP	SO	Dec-20	(53,261)
Hortonworks SW	UAE 3.9 New Capital Additions	404IP	SO	Jun-21	33,893
Vegetation Management (PVM/Mobile)	UAE 3.9 New Capital Additions	404IP	SO	Dec-21	4,345
Compass Replacement	UAE 3.9 New Capital Additions	404IP	SO	Dec-21	5,317
					(335,664)
					(18,650,639)

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Project Description	Notes	FERC Account	Factor	In-Service	Dec 21 Accum Depr Reserve	December 2021 13 Month Avg
Steam Production						
Hunter 303 CCR Forced Oxidation Project	UAE 3.9	108SP	SG	Jun-21	384,242	111,407
Naughton U1 OH Turbine Major (HP/IP/LP) CY21	UAE 3.9	108SP	SG	Dec-21	7,758	597
Wyodak U1 - Boiler Waterwall Replacement CY20/CY21	UAE 3.9	108SP	SG	May-21	101,234	33,225
Craig CRGU5 RELIABILITY/ABILITY TO SERVE CY20	UAE 3.9	108SP	SG	Dec-20	104,519	53,726
Craig CRGU0 NEW COAL STORAGE SILOS CY21	UAE 3.9	108SP	SG	Dec-21	4,149	319
Jim Bridger U2 Burners Major 21	UAE 3.9	108SP	SG	Jun-21	51,539	14,943
Craig CRGU5 REGULATORY ENVIRON & SAFETY CY20	UAE 3.9	108SP	SG	Dec-20	81,293	41,787
Wyodak U1 - Ovation Major Upgrade CY21	UAE 3.9	108SP	SG	May-21	49,260	16,167
Colstrip COLU5 CCR-CONSTRUCt DRY WASTE DISPOSAL CY21 TUCK	UAE 3.9	108SP	SG	Dec-21	2,584	199
Wyodak U1 - Pulverizer Overhaul "A" CY21	UAE 3.9	108SP	SG	Apr-21	43,287	15,865
Wyodak U1 - Scrubber 'A' Chamber Reinforcement CY19/CY20	UAE 3.9	108SP	SG	May-21	33,849	11,110
Wyodak U1 - Pulverizer Overhaul "C" CY21	UAE 3.9 New Capital Additions	108SP	SG	Dec-21	(7,514)	(771)
Wyodak U1 - Pulverizer Overhaul "D" CY21	UAE 3.9 New Capital Additions	108SP	SG	Oct-20	(68,968)	(38,833)
Naughton U2 OH Mechanical Dust Collectors CY20	UAE 3.9 New Capital Additions	108SP	SG	May-21	(45,701)	(14,999)
Naughton U2 OH Boiler: Header Replacement CY20	UAE 3.9 New Capital Additions	108SP	SG	May-21	(47,988)	(15,750)
Steam Production Total					**693,541**	**228,992**
Hydro Production Plant						
Soda Spinning Reserve	UAE 3.9	108HP	SG-U	Sep-21	63,321	11,133
Swift 1 Spillway Gate Bulkhead	UAE 3.9	108HP	SG-P	Jun-21	65,507	18,993
Toketee Dam Rehabilitation Evaluation	UAE 3.9	108HP	SG-P	Dec-21	4,060	312
Swift 1 Spillway Gate Retrofit	UAE 3.9	108HP	SG-P	Oct-21	17,455	2,417
Swift 1 Minimum Discharge Line	UAE 3.9	108HP	SG-P	Nov-20	70,614	39,007
Bull Trout Yale Downstream Facility	UAE 3.9	108HP	SG-P	Nov-21	5,898	605
Yale Spillway Gate Improvements	UAE 3.9	108HP	SG-P	Dec-21	1,804	139
ILR 4.4.1 Swift FSC NTS Upgrade Phase 2	UAE 3.9	108HP	SG-P	Dec-21	1,579	121
Eastside Flowline Removal	UAE 3.9	108HP	SG-P	Nov-20	34,652	19,141
ILR 4.4.1 Swift FSC Attract Pump DM Mod	UAE 3.9	108HP	SG-P	Dec-21	1,250	96
Yale Saddle Dam Seismic Remediation	UAE 3.9 New Capital Additions	108HP	SG-P	Nov-21	(6,012)	(617)
					260,128	**91,349**
Other Production						
Lakeside Blk 1 U12 Generator Rotor Replacement	UAE 3.9	108OP	SG	Apr-20	117,199	80,469
Hermiston U1 - OH - Stator/Generator rewind	UAE 3.9 New Capital Additions	108OP	SG	Dec-20	(38,036)	(19,661)
Currant Creek U3 ST Diaphragm Replacement	UAE 3.9 New Capital Additions	108OP	SG	Apr-20	(62,392)	(42,838)
Cedar Springs Wind Project 200 MW 2020	Remove as Filed	108OP	SG-W	Dec-20	[redacted]	[redacted]
Cedar Springs Wind Project 200 MW 2020	Remove as Filed	108OP	SG-W	Dec-20	[redacted]	[redacted]
Ekola Flats Wind Project 250 MW 2020	Remove as Filed	108OP	SG-W	Dec-20	[redacted]	[redacted]
TB Flats Wind Project 500 MW 2020	Remove as Filed	108OP	SG-W	Dec-20	[redacted]	[redacted]
Pryor Mtn Wind Project 240 MW 2020	Remove as Filed	108OP	SG-W	Dec-20	[redacted]	[redacted]
Cedar Springs Wind Project 200 MW 2020	Update Project Data	108OP	SG-W	Nov-20	[redacted]	[redacted]
Ekola Flats Wind Project 250 MW 2020	Update Project Data	108OP	SG-W	Various	[redacted]	[redacted]
TB Flats Wind Project 500 MW 2020	Update Project Data	108OP	SG-W	Various	[redacted]	[redacted]
Pryor Mtn Wind Project 240 MW 2020	Update Project Data	108OP	SG-W	Various	[redacted]	[redacted]
Other Production Total					**13,247,387**	**5,493,529**
Transmission						
TMP Transmission Major Projects - PP (Flint New 115kV to 12.5kV Substation)	UAE 3.9	108TP	SG	Various	157,355	80,389
TMP Trans Main Grid West (Shevlin Park Substation Increase Capacity)	UAE 3.9	108TP	SG	Various	33,619	16,030
Blue Creek - Bothwell Tap 46 kV Reconductor/Rebuild	UAE 3.9 New Capital Additions	108TP	SG	May-21	(21,346)	(7,006)
Southeast - Install New Control Building	UAE 3.9 New Capital Additions	108TP	SG	Dec-21	(729)	(56)
Spare 230-161kV 150 MVA Xfmr	UAE 3.9 New Capital Additions	108TP	SG	Sep-21	(5,015)	(882)
UDOT I-15 NB; Bangerter Hwy to I-215	UAE 3.9 New Capital Additions	108TP	SG	Oct-20	(47,022)	(27,625)
Tyson Foods, 8 MW	UAE 3.9 New Capital Additions	108TP	SG	Dec-20	(26,415)	(13,745)
El Monte Substation Expansion	UAE 3.9 New Capital Additions	108TP	SG	Mar-20	(82,048)	(59,331)
Wildfire Mitigation - Trans	Remove as Filed	108TP	SG	Various	618,561	325,995
Wildfire Mitigation - Trans	Update Project Data	108TP	SG	Various	(422,917)	(188,042)
Pavant Transformer Protection	Remove as Filed	108TP	SG	Dec-20	32,618	16,972
Jordanelle - Midway Construct 138 kV Line	Remove as Filed	108TP	SG	Nov-20	354,429	197,218
Reroute JB Goshen 345kV line	Remove as Filed	108TP	SG	Oct-20	40,834	23,989
Parowan Valley Reg Replacement	Remove as Filed	108TP	SG	Dec-20	17,383	9,045
Block 216 Tower Service Request	Remove as Filed	108TP	SG	Oct-20	17,032	9,960
Pavant Transformer Protection	Update Project Data	108TP	SG	Dec-20	(23,522)	(12,240)
Jordanelle - Midway Construct 138 kV Line	Update Project Data	108TP	SG	Nov-21	(54,190)	(5,558)
Reroute JB Goshen 345kV line	Update Project Data	108TP	SG	Oct-21	(12,313)	(1,705)
Total Transmission					**576,315**	**363,411**

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Project Description	Notes	FERC Account	Factor	In-Service	Dec 21 Accum Depr Reserve	December 2021 13 Month Avg
Distribution						
AMI - Utah Meters 2019 -2020	Remove as Filed	108364	UT	Dec-20	480,656	183,572
AMI - Utah Meters - 2021	Update Project Data	108364	UT	Various	(108,947)	(15,289)
Wildfire Mitigation - Dist	Remove as Filed	108364	UT	Various	1,362,013	767,221
Wildfire Mitigation - Dist	Update Project Data	108364	UT	Various	(823,924)	(413,660)
Timp Install New 12kV Transformer	UAE 3.9	108364	UT	May-21	100,244	32,900
Healthy Mountain Farms LLC, 5 MW New Load - Phase 1	UAE 3.9 New Capital Additions	108364	UT	Oct-21	(18,925)	(2,620)
WPR Development Company, 18.725 MW	UAE 3.9 New Capital Additions	108364	UT	Nov-21	(17,285)	(1,773)
Temple Square - 1.58 MW load addn in Downtown SLC	UAE 3.9 New Capital Additions	108364	UT	Oct-21	(8,055)	(1,115)
118th S 6400 W Substation Property Acquisition	UAE 3.9 New Capital Additions	108364	UT	Jul-21	(24,280)	(6,113)
Pony Express Enable Mobile Installation	UAE 3.9 New Capital Additions	108364	UT	May-21	(15,880)	(5,212)
Terminal: Const T&D Training Facility	UAE 3.9 New Capital Additions	108364	UT	Aug-20	(84,655)	(54,083)
Parowan Valley Reg Replacement	Update Project Data	108364	UT	Dec-20	(25,696)	(13,375)
Block 216 Tower Service Request	Update Project Data	108364	OR	Oct-20	(25,461)	(14,818)
Total Distribution					**789,805**	**455,635**
General						
AMI - Utah IT Comm Network	Remove as Filed	108GP	UT	Dec-20	976,450	477,796
AMI - Utah IT Comm Network	Update Project Data	108GP	UT	Dec-20	(173,210)	(52,614)
Wildfire Mitigation - General	Update Project Data	108GP	UT	Various	(101,012)	(61,621)
Field Ai	UAE 3.9	108GP	SO	Dec-21	4,414	340
Microsoft Office Upgrade	UAE 3.9	108GP	SO	Various	46,745	24,957
Vernal to Antelope diversity loop	UAE 3.9	108GP	SG	Dec-21	1,500	115
Electric Vehicle Infrastructure (HB 396)	UAE 3.9 New Capital Additions	108GP	UT	Various	(8,276)	(637)
Total General					**746,612**	**388,336**
Intangible						
Field Ai	UAE 3.9	111IP	SO	Dec-21	15,059	1,158
WEST	UAE 3.9	111IP	SO	Dec-20	198,142	103,034
AMI Headend- SSN/Itron Conversion	UAE 3.9	111IP	SO	Dec-21	4,175	321
Large Customer microsite	UAE 3.9	111IP	SO	Dec-21	2,378	183
Replace PAR/SO - Integrated Resource Plan (IRP) software	UAE 3.9	111IP	SO	Jul-20	83,220	54,687
Landlord microsite	UAE 3.9	111IP	SO	Dec-20	59,443	30,910
SMS check balance , pay bill	UAE 3.9	111IP	SO	Dec-20	55,480	28,850
Hortonworks SW	UAE 3.9 New Capital Additions	111IP	SO	Jun-21	(33,893)	(9,827)
Vegetation Management (PVM/Mobile)	UAE 3.9 New Capital Additions	111IP	SO	Dec-21	(4,345)	(334)
Compass Replacement	UAE 3.9 New Capital Additions	111IP	SO	Dec-21	(5,317)	(409)
					374,341	**208,573**
					16,688,130	**7,229,826**

Rocky Mountain Power
Utah General Rate Case - December 2021
Repowering Capital Additions

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED	REF#
Adjustment to Rate Base:							
Capital Additions - Wind	343	3	5,999,071	SG-W	43.997%	2,639,441	10.21.1
Adjustment to Depreciation Expense:							
Capital Additions - Wind Depr. Expense	403OP	3	290,247	SG-W	43.997%	127,701	10.21.1
Adjustment to Depreciation Reserve:							
Capital Additions - Wind Depr. Reserve	108OP	3	(268,703)	SG-W	43.997%	(118,222)	10.21.1
Adjustment to Tax:							
Schedule M Adjustment	SCHMAT	3	290,247	SG	43.997%	127,701	
Schedule M Adjustment	SCHMDT	3	1,919,702	SG	43.997%	844,621	
Deferred Income Tax Expense	41110	3	(71,362)	SG	43.997%	(31,397)	
Deferred Income Tax Expense	41010	3	471,989	SG	43.997%	207,663	
Accumulated Def Inc Tax Balance	282	3	(387,531)	SG	43.997%	(170,504)	

Description of Adjustment:

This adjustment adds the trailing capital additions for the repowering projects that were in-service in the Base Period.

Rocky Mountain Power
Utah General Rate Case - December 2021
Repowering Capital Additions

Electric Plant in Service

	Account	Factor	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	13 Month Avg Dec-21
Other Plant Wind	343	SG-W	5,999,071	5,999,071	5,999,071	5,999,071	5,999,071	5,999,071	5,999,071	5,999,071	5,999,071	5,999,071	5,999,071	5,999,071	5,999,071	5,999,071
																Ref. 10.21.2

Depreciation Expense*

	Account	Factor	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	12 ME Dec-21
Other Plant Wind	403OP	SG-W	24,187	24,187	24,187	24,187	24,187	24,187	24,187	24,187	24,187	24,187	24,187	24,187	290,247

Depreciation Reserve

	Account	Factor	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	13 Month Avg Dec-21
Other Plant Wind	108OP	SG-W	(123,579)	(147,766)	(171,954)	(196,141)	(220,328)	(244,515)	(268,703)	(292,890)	(317,077)	(341,264)	(365,451)	(389,639)	(413,826)	(268,703)

**Proposed Composite Depreciation Rate - Wind* *4.838%*

Rocky Mountain Power
Utah General Rate Case - December 2021
Repowering Capital Additions

Project	Date	Project Capital Amount	
Incremental New Wind Cap Adds			
Glenrock 1 Repowering	Various	1,957,067	
Glenrock 3 Repowering	Various	892,482	
Goodnoe Hills Repowering	Various	(701,080)	
High Plains Repowering	Various	91,716	
Leaning Juniper Repowering	Various	704,032	
McFadden Ridge Repowering	Various	185,387	
Rolling Hills Repowering	Various	1,328,336	
Seven Mile 1 Repowering	Various	1,267,135	
Seven Mile 2 Repowering	Various	273,995	
		5,999,071	**Ref 10.21.1**

Rocky Mountain Power
Utah General Rate Case - December 2021
Pryor Mountain and TB Flats – Phase 2

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED	REF#
Adjustment to Rate Base:							
Capital Additions - Wind	343	3	357,704,000	SG-W	43.997%	157,380,811	10.22.1
Adjustment to Depreciation Expense:							
Capital Additions - Wind Depr. Expense	403OP	3	17,306,406	SG-W	43.997%	7,614,386	10.22.1
Adjustment to Depreciation Reserve:							
Capital Additions - Wind Depr. Reserve	108OP	3	(9,374,303)	SG-W	43.997%	(4,124,459)	10.22.1
Adjustment to Operations & Maintenance Expense:							
Incremental Wind Repowering O&M Expense	549	3	2,535,501	SG	43.997%	1,115,557	10.22.2
Adjustment to Tax:							
Schedule M Adjustment	SCHMAT	3	17,306,406	SG	43.997%	7,614,386	
Schedule M Adjustment	SCHMDT	3	90,802,521	SG	43.997%	39,950,837	
Deferred Income Tax Expense	41110	3	(4,255,057)	SG	43.997%	(1,872,119)	
Deferred Income Tax Expense	41010	3	22,325,253	SG	43.997%	9,822,553	
Deferred Income Tax Expense - Flowthrough	41010	3	140,028	SG	43.997%	61,609	
Accumulated Def Inc Tax Balance	282	3	(11,959,027)	SG	43.997%	(5,261,673)	

Description of Adjustment:

This adjustment reflects the full first-year revenue requirement associated with the delayed portions of TB Flats and Pryor Mountain. Additional details on the delays on these projects are provided in the testimonies of Mr. Van Engelenhoven and Mr. Hemstreet.

Rocky Mountain Power
Utah General Rate Case - December 2021
Pryor Mountain and TB Flats – Phase 2

Electric Plant in Service

	Account	Factor	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	13 Month Avg Jun-22
Other Plant Wind	343	SG-W	357,704,000	357,704,000	357,704,000	357,704,000	357,704,000	357,704,000	357,704,000	357,704,000	357,704,000	357,704,000	357,704,000	357,704,000	357,704,000	357,704,000
																Ref. 10.22.2

Depreciation Expense*

	Account	Factor	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	12 ME Jun 22
Other Plant Wind	403OP	SG-W	1,442,200	1,442,200	1,442,200	1,442,200	1,442,200	1,442,200	1,442,200	1,442,200	1,442,200	1,442,200	1,442,200	1,442,200	17,306,406
															Ref. 10.22.2

Depreciation Reserve

	Account	Factor	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	13 Month Avg Jun-22
Other Plant Wind	108OP	SG-W	(721,100)	(2,163,301)	(3,605,501)	(5,047,702)	(6,489,902)	(7,932,103)	(9,374,303)	(10,816,504)	(12,258,704)	(13,700,905)	(15,143,105)	(16,585,306)	(18,027,506)	(9,374,303)
																Ref. 10.22.2

**Proposed Composite Depreciation Rate - Wind* *4.838%*

Rocky Mountain Power
Utah General Rate Case - December 2021
Pryor Mountain and TB Flats – Phase 2
REDACTED

Project	Date	Project Capital Amount	
Incremental New Wind Cap Adds			
Pryor Mtn Wind Project 240 MW 2020	Jun-2021	[redacted]	
TB Flats Wind Project 500 MW 2020	Jun-2021		
		357,704,000	**Ref 10.22.1**

Incremental O&M	**2021 O&M**	
Pryor Mtn Wind Project 240 MW 2020	[redacted]	
TB Flats Wind Project 500 MW 2020		
	2,535,501	**Ref 10.22**

Rocky Mountain Power
Utah December 2021 General Rate Case
Deer Creek Mine Closure
Closing Costs in Pro Forma Period - Update

Allocation	December 2019 Closure Costs		REBUTTAL UPDATE Total Utah Allocated amount	AS FILED Total Utah Allocated amount	INCREMENTAL Total Utah Allocated amount	Ref. #
SE	Closure costs excluding Recovery Royalties	60,794,284	26,358,097	26,358,097	-	
UT	Carrying Charge on Closure costs	5,788,049	5,788,049	5,788,049	-	
Total			**32,146,146**	**32,146,146**	**-**	

Allocation	Rebuttal Adjustments	Total Utah Allocated amount	Total Utah Allocated amount	Total Utah Allocated amount
UT	Remove accrued carrying charge on recovery royalties	(430,286)		(430,286)
		(430,286)		**(430,286)**

31,715,861

UT GRC SE%	43.36%

Date	Beg Bal	Deferral	End Bal	End Bal	End Bal	
Dec-19			31,715,861	32,146,146	(430,286)	
Jan-20	31,715,861	22,779	31,738,639	32,168,925	(430,286)	
Feb-20	31,738,639	3,455	31,742,094	32,172,380	(430,286)	
Mar-20	31,742,094	5,533	31,747,628	32,177,913	(430,286)	
Apr-20	31,747,628	5,533	31,753,161	32,183,447	(430,286)	
May-20	31,753,161	3,455	31,756,616	32,186,902	(430,286)	
Jun-20	31,756,616	13,847	31,770,463	32,200,748	(430,286)	
Jul-20	31,770,463	13,847	31,784,309	32,214,595	(430,286)	
Aug-20	31,784,309	3,455	31,787,764	32,218,050	(430,286)	
Sep-20	31,787,764	3,455	31,791,219	32,221,505	(430,286)	
Oct-20	31,791,219	3,455	31,794,674	32,224,960	(430,286)	
Nov-20	31,794,674	3,455	31,798,129	32,228,415	(430,286)	
Dec-20	31,798,129	3,455	**31,801,584**	**32,231,870**	**(430,286)**	**10.23.1**

Year End Balance
Ref. 8.14.3

	REBUTTAL UPDATE	AS FILED	INCREMENTAL	Ref. #
Total Company revised estimated Test Period Recovery Royalties *	16,304,548			
Joint Owner Share	(673,114)			
Utah Allocated revised estimated Test Period Recovery Royalties *	**6,777,197**	**5,249,190**	**1,528,007**	**10.23.1**
Total Change from Filed			**1,097,722**	**10.23.1**

*Recovery royalties, which are part of the Deer Creek mine closure costs, have been estimated but not spent.

Rocky Mountain Power
Utah December 2021 General Rate Case
Deer Creek Mine Closure Cost - Update
EDIT Offset

The Company is proposing to buy-down Utah's share of Deer Creek Mine total balance as of December 31, 2020 using the deferred EDIT regulatory liability balance.

Description	December 2020 Balance Filed	December 2020 Balance Revised	Incremental Differ.	Reference
Utah share of Deer Creek Mine closure cost	$ 32,231,870	$ 31,801,584	$ (430,286)	**Ref. 10.23**
Utah share of savings resulting from Deer Creek Mine closure	$ (22,371,177)	$ (22,371,177)	$ -	
Utah share of Retiree Medical Obligation Settlement Loss	$ 5,471,658	$ 5,471,658	$ -	
Utah share of recovery royalties	$ 5,249,190	$ 6,777,197	$ 1,528,007	**Ref. 10.23**
Total Deer Creek Balances	$ 20,581,541	$ 21,679,262	$ 1,097,722	
Buy-down using the deferred EDIT regulatory liability balance	$ (20,581,541)	$ (21,679,262)	$ (1,097,722)	Exhibit 5R
Utah share of Deer Creek Mine net balance	**$ -**	**$ -**	**$ -**	

Utah General Rate Case
Pro Forma Factors December 2021
2020 Protocol Rebuttal Normalized Average Factors

Utah General Rate Case
December 2021
13 MONTH AVERAGE FACTORS

DESCRIPTION	2020 PROTOCOL FACTOR	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
Situs	S	-	-	-	-	-	-	-			Situs
System Generation	SG	1.5367%	26.0226%	7.8920%	43.9975%	5.8975%	14.6253%	0.0283%			11.16
Divisional Generation - Pac. Power	DGP	3.2512%	55.0569%	16.6974%	0.0000%	0.0000%	24.9944%	0.0000%			11.16
Divisional Generation - R.M.P.	DGU	0.0000%	0.0000%	0.0000%	83.4313%	11.1832%	5.3318%	0.0537%			11.16
System Capacity	SC	1.5641%	26.3297%	8.0168%	44.2113%	5.6774%	14.1738%	0.0269%			11.16
System Energy	SE	1.4544%	25.1015%	7.5177%	43.3562%	6.5577%	15.9800%	0.0326%			11.16
System Overhead	SO	2.2164%	27.1946%	7.6912%	43.5947%	5.7585%	13.5244%	0.0202%	0.0000%	0.0000%	11.8
Gross Plant-System	GPS	2.2164%	27.1946%	7.6912%	43.5947%	5.7585%	13.5244%	0.0202%	0.0000%	0.0000%	11.7
System Net Plant	SNP	2.0425%	26.5998%	7.5302%	44.2057%	5.8611%	13.7221%	0.0215%	0.0172%	0.0000%	11.7
Division Net Plant Distribution	SNPD	3.5005%	27.0225%	6.1726%	48.2182%	5.1533%	9.9329%	0.0000%			11.6
Customer - System	CN	2.3964%	31.2408%	6.9317%	47.8094%	4.1998%	7.4219%	0.0000%	0.00%	0.00%	11.10
CIAC	CIAC	3.5005%	27.0225%	6.1726%	48.2182%	5.1533%	9.9329%	0.0000%			11.11
Bad Debt Expense	BADDEBT	5.6349%	38.0965%	10.3019%	32.5870%	5.0658%	8.3139%	0.0000%	0.0000%	0.0000%	11.10
Accumulated Investment Tax Credit 1984	ITC84	3.29%	70.98%	14.18%						0.61%	Fixed
Accumulated Investment Tax Credit 1985	ITC85	5.42%	67.69%	13.36%						1.92%	Fixed
Accumulated Investment Tax Credit 1986	ITC86	4.79%	64.61%	13.13%						1.98%	Fixed
Accumulated Investment Tax Credit 1988	ITC88	4.27%	61.20%	14.96%						2.86%	Fixed
Accumulated Investment Tax Credit 1989	ITC89	4.88%	56.36%	15.27%						2.82%	Fixed
Accumulated Investment Tax Credit 1990	ITC90	1.50%	15.94%	3.91%	46.94%	13.98%	17.3435%			0.39%	Fixed
Other Electric	OTHER	0.00%	0.00%	0.00%	0.00%	0.00%	0.0000%	0.00%	100.00%	0.00%	Situs
Non-Regulated	NUTIL	0.00%	0.00%	0.00%	0.00%	0.00%	0.0000%	0.00%	0.00%	100.00%	Situs
System Net Steam Plant	SNPPS	1.6404%	27.7793%	8.4248%	40.1566%	6.3331%	15.6355%	0.0303%	0.0000%	0.0000%	See SG
System Net Transmission Plant	SNPT	1.5367%	26.0226%	7.8920%	43.9975%	5.8975%	14.6253%	0.0283%			See SG
System Net Production Plant	SNPP	1.5724%	26.6288%	8.0754%	42.6350%	6.0476%	14.9732%	0.0290%	0.0385%	0.0000%	See SG
System Net Hydro Plant	SNPPH	1.5278%	25.8720%	7.8464%	43.7428%	5.8633%	14.5407%	0.0282%	0.5789%	0.0000%	See SG
System Net Other Production Plant	SNPPO	1.5367%	26.0244%	7.8918%	43.9964%	5.8973%	14.6250%	0.0283%	0.0000%	0.0000%	See SG
System Net General Plant	SNPG	2.4923%	27.9620%	6.5661%	41.0040%	7.2879%	14.6760%	0.0116%			See SG
System Net Intangible Plant	SNPI	2.0761%	26.4742%	7.8269%	42.8926%	6.3801%	14.3288%	0.0214%			See SG
Trojan Plant Allocator	TROJP	1.5242%	25.8827%	7.8352%	43.9001%	5.9978%	14.8311%	0.0290%			11.13
Trojan Decommissioning Allocator	TROJD	1.5220%	25.8580%	7.8251%	43.8829%	6.0155%	14.8674%	0.0291%			11.13
DIT Balance	DITBAL	2.2073%	25.2462%	6.5038%	44.0661%	5.7990%	14.5236%	0.2292%	0.0000%	1.4249%	11.10
Tax Depreciation	TAXDEPR	2.0357%	26.3504%	6.4804%	44.9508%	5.6497%	13.4808%	0.0204%	1.0319%	0.0000%	11.14
SCHMAT Depreciation Expense	SCHMDEXP	2.1066%	26.9749%	7.8130%	43.4745%	5.7710%	13.8381%	0.0219%	0.0000%	0.0000%	11.13
System Generation Cholla Transaction	SGCT	1.5371%	26.0300%	7.8943%	44.0100%	5.8991%	14.6295%				See SG

13 MONTH AVERAGE FACTORS
CALCULATION OF INTERNAL FACTORS

DESCRIPTION OF FACTOR		TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility
STEAM :											
STEAM PRODUCTION PLANT											
	S	0	0	0	0	0	0	0	0	0	0
	DGP	0	0	0	0	0	0	0	0	0	0
	DGU	0	0	0	0	0	0	0	0	0	0
	SG	6,847,699,757	105,228,751	1,781,951,747	540,423,128	3,012,816,573	403,841,016	1,003,427,822	1,940,571	0	0
	SSGCH	0	0	0	0	0	0	0	0	0	0
		6,847,699,757	105,228,751	1,781,951,747	540,423,128	3,012,816,573	403,841,016	1,003,427,822	1,940,571	0	0
LESS ACCUMULATED DEPRECIATION											
	S	(220,924,579)	-	-	-	(222,899,213)	1,226,391	748,243	-	-	-
	DGP	(825,600,764)	(12,687,025)	(214,843,053)	(65,156,733)	(363,243,681)	(48,689,555)	(120,746,750)	(233,967)	0	0
	DGU	(779,379,519)	(11,976,742)	(202,815,068)	(61,508,935)	(342,907,489)	(45,963,671)	(113,986,745)	(220,868)	0	0
	SG	(1,482,741,438)	(22,785,320)	(385,848,356)	(117,018,531)	(652,369,136)	(87,444,227)	(216,889,164)	(420,194)	0	0
	SG-W	0	0	0	0	0	0	0	0	0	0
	SSGCH	(266,435,549)	(4,094,321)	(69,333,544)	(21,027,197)	(117,224,976)	(15,712,956)	(38,967,050)	(75,505)	0	0
		(3,575,081,849)	(51,543,408)	(872,840,022)	(264,711,396)	(1,698,644,495)	(196,584,017)	(489,841,467)	(950,535)	0	0

Utah General Rate Case
December 2021
13 MONTH AVERAGE FACTORS

DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
TOTAL NET STEAM PLANT		3,272,617,908	53,685,343	909,111,725	275,711,732	1,314,172,078	207,257,000	513,586,355	990,036	0	0	
SNPPS												
SYSTEM NET PLANT PRODUCTION STEAM		100.0000%	1.6404%	27.7793%	8.4248%	40.1566%	6.3331%	15.6315%	0.0303%	0.0000%	0.0000%	
NUCLEAR:		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**			
NUCLEAR PRODUCTION PLANT												
	DGP	0	0	0	0	0	0	0	0			
	DGU	0	0	0	0	0	0	0	0			
	SG	0	0	0	0	0	0	0	0			
		0	0	0	0	0	0	0	0			
LESS ACCUMULATED DEPRECIATION												
	DGP	0	0	0	0	0	0	0	0			
	DGU	0	0	0	0	0	0	0	0			
	SG	0	0	0	0	0	0	0	0			
		0	0	0	0	0	0	0	0			
TOTAL NUCLEAR PLANT		0	0	0	0	0	0	0	0			
SNPPN												
SYSTEM NET PLANT PRODUCTION NUCLEAR		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%			
HYDRO:		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**Other**	**Non-Utility**	
HYDRO PRODUCTION PLANT												
	S	0	0	0	0	0	0	0	0	0	0	
	DGP	0	0	0	0	0	0	0	0	0	0	
	DGU	0	0	0	0	0	0	0	0	0	0	
	SG	1,112,189,220	17,091,036	289,420,914	87,774,406	489,335,431	65,591,022	163,898,189	315,183	0	0	
		1,112,189,220	17,091,036	289,420,914	87,774,406	489,335,431	65,591,022	163,898,189	315,183	0	0	
LESS ACCUMULATED DEPRECIATION (incl hydro amortization)												
	S	3,600,961	-	-	-	-	-	-	-	3,600,961	-	
	DGP	(149,229,814)	(2,293,218)	(38,833,526)	(11,777,275)	(65,657,385)	(8,800,783)	(21,825,337)	(42,290)	0	0	
	DGU	(32,759,104)	(503,410)	(8,524,781)	(2,585,361)	(14,413,186)	(1,931,958)	(4,791,124)	(9,284)	0	0	
	SG	(311,748,441)	(4,790,645)	(81,125,151)	(24,603,308)	(137,161,514)	(18,385,270)	(45,607,566)	(88,346)	0	0	
		(490,136,398)	(7,587,273)	(128,483,459)	(38,965,944)	(217,232,085)	(29,118,011)	(72,224,026)	(139,920)	3,600,961	0	
TOTAL NET HYDRO PRODUCTION PLANT		622,052,822	9,503,763	160,937,455	48,808,461	272,103,346	36,473,011	91,674,163	175,263	3,600,961	0	
SNPPH												
SYSTEM NET PLANT PRODUCTION HYDRO		100.0000%	1.5278%	25.8720%	7.8464%	43.7428%	5.8633%	14.5418%	0.0282%	0.5789%	0.0000%	
OTHER:		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**Other**	**Non-Utility**	
OTHER PRODUCTION PLANT (EXCLUDES EXPERIMENTAL)												
	S	133,637	-	133,637	-	-	-	-	-	-	-	
	DGP & DGU	0	0	0	0	0	0	0	0	0	0	
	SG	5,618,806,964	86,344,329	1,462,161,491	443,438,431	2,472,134,489	331,367,437	815,429,220	1,592,315	0	0	
	SSGCT	0	0	0	0	0	0	0	0	0	0	
		5,618,940,601	86,344,329	1,462,295,129	443,438,431	2,472,134,489	331,367,437	815,429,220	1,592,315	0	0	
LESS ACCUMULATED DEPRECIATION												
	S	0	0	0	0	0	0	0	0	0	0	
	DGP	368,629,279	5,664,734	95,927,043	29,092,366	162,187,660	21,739,800	55,323,530	104,466	0	0	
	DGU	0	0	0	0	0	0	0	0	0	0	
	SG	(493,255,119)	(7,579,862)	(128,357,967)	(38,927,886)	(217,019,912)	(29,089,571)	(72,943,583)	(139,784)	0	0	
	SSGCT	(42,818,301)	(657,990)	(11,142,449)	(3,379,237)	(18,838,981)	(2,525,196)	(6,262,313)	(12,134)	0	0	
		(167,444,140)	(2,573,118)	(43,573,373)	(13,214,757)	(73,671,232)	(9,874,967)	(23,882,366)	(47,452)	0	0	
TOTAL NET OTHER PRODUCTION PLANT		5,451,496,461	83,771,211	1,418,721,755	430,223,674	2,398,463,257	321,492,469	791,546,854	1,544,862	0	0	
SNPPO												
SYSTEM NET PLANT PRODUCTION OTHER		100.0000%	1.5367%	26.0244%	7.8918%	43.9964%	5.8973%	14.6250%	0.0283%	0.0000%	0.0000%	

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PRODUCTION:		TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility	
TOTAL PRODUCTION PLANT												
	S	133,637	0	133,637	0	0	0	0	0	0	0	
	DGP & DGU	0	0	0	0	0	0	0	0	0	0	
	SG	13,578,695,941	208,664,116	3,533,534,153	1,071,635,965	5,974,286,493	800,799,475	1,982,755,231	3,848,069	0	0	
	SSGCH	0	0	0	0	0	0	0	0	0	0	
	SSGCT	0	0	0	0	0	0	0	0	0	0	
		13,578,829,578	208,664,116	3,533,667,790	1,071,635,965	5,974,286,493	800,799,475	1,982,755,231	3,848,069	0	0	
LESS ACCUMULATED DEPRECIATION												
	S	(217,323,618)	-	-	-	(222,899,213)	1,226,391	748,243	-	3,600,961	-	
	DGP	0	0	0	0	0	0	0	0	0	0	
	DGU	0	0	0	0	0	0	0	0	0	0	
	SG	(4,015,338,769)	(61,703,798)	(1,044,896,854)	(316,892,097)	(1,766,648,600)	(236,803,386)	(586,696,102)	(1,137,907)	0	0	
	SSGCH	0	0	0	0	0	0	0	0	0	0	
	SSGCT	0	0	0	0	0	0	0	0	0	0	
		(4,232,662,387)	(61,703,798)	(1,044,896,854)	(316,892,097)	(1,989,547,812)	(235,576,995)	(585,947,860)	(1,137,907)	3,600,961	0	
TOTAL NET PRODUCTION PLANT		9,346,167,191	146,960,318	2,488,770,936	754,743,867	3,984,738,680	565,222,480	1,396,807,372	2,710,161	3,600,961	0	
SNPP												
SYSTEM NET PRODUCTION PLANT		100.0000%	1.5724%	26.6288%	8.0754%	42.6350%	6.0476%	14.9739%	0.0290%	0.0385%	0.0000%	
TRANSMISSION:		TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC			
TRANSMISSION PLANT												
	DGP	0	0	0	0	0	0	0	0			
	DGU	0	0	0	0	0	0	0	0			
	SG	7,626,615,097	117,198,360	1,984,646,024	601,895,430	3,355,519,835	449,777,312	1,119,511,773	2,161,308			
		7,626,615,097	117,198,360	1,984,646,024	601,895,430	3,355,519,835	449,777,312	1,119,511,773	2,161,308			
LESS ACCUMULATED DEPRECIATION												
	DGP	(369,846,223)	(5,683,435)	(96,243,724)	(29,188,408)	(162,723,085)	(21,811,569)	(54,091,192)	(104,811)			
	DGU	(439,311,441)	(6,750,908)	(114,320,402)	(34,670,630)	(193,286,043)	(25,908,259)	(64,250,702)	(124,497)			
	SG	(1,204,114,192)	(18,503,649)	(313,342,212)	(95,029,160)	(529,780,119)	(71,012,269)	(176,158,698)	(341,234)			
		(2,013,271,856)	(30,937,992)	(523,906,338)	(158,888,198)	(885,789,247)	(118,732,097)	(294,500,592)	(570,541)			
TOTAL NET TRANSMISSION PLANT		5,613,343,240	86,260,368	1,460,739,687	443,007,232	2,469,730,587	331,045,215	825,011,181	1,590,766			
SNPT												
SYSTEM NET PLANT TRANSMISSION		100.0000%	1.5367%	26.0226%	7.8920%	43.9975%	5.8975%	14.6253%	0.0283%			
DISTRIBUTION:		TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC			
DISTRIBUTION PLANT - PACIFIC POWER												
	S	3,925,753,276	316,089,799	2,356,767,630	567,031,645	0	0	685,864,202	0			
LESS ACCUMULATED DEPRECIATION												
	S	(1,800,011,124)	(150,523,501)	(1,078,675,583)	(275,084,470)	0	0	-295,727,570	0			
		2,125,742,152	165,566,298	1,278,092,047	291,947,176	0	0	390,136,631	0			
DNPDP												
DIVISION NET PLANT DISTRIBUTION PACIFIC POWER		100.0000%	7.7886%	60.1245%	13.7339%	0.0000%	0.0000%	18.3599%	0.0000%			
DISTRIBUTION PLANT - ROCKY MOUNTAIN POWER												
	S	3,926,486,521	0	0	0	3,382,226,861	405,767,171	138,492,489	0			
LESS ACCUMULATED DEPRECIATION												
	S	(1,322,493,500)	0	0	0	(1,101,632,566)	(162,030,813)	(58,830,121)	0			
		2,603,993,021	0	0	0	2,280,594,295	243,736,358	79,662,368	0			
DNPDU												
DIVISION NET PLANT DISTRIBUTION R.M.P.		100.0000%	0.0000%	0.0000%	0.0000%	87.5807%	9.3601%	3.0313%	0.0000%			
TOTAL NET DISTRIBUTION PLANT		4,729,735,173	165,566,298	1,278,092,047	291,947,176	2,280,594,295	243,736,358	469,798,999	0			
DNPD & SNPD												
DIVISION NET PLANT DISTRIBUTION		100.0000%	3.5005%	27.0225%	6.1726%	48.2182%	5.1533%	9.8844%	0.0000%			

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GENERAL:		TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC			
GENERAL PLANT												
	S	707,431,477	21,529,336	222,507,124	48,510,697	258,675,938	55,954,111	100,254,271	0			
	DGP	0	0	0	0	0	0	0	0			
	DGU	0	0	0	0	0	0	0	0			
	SE	3,887,400	56,537	975,795	292,245	1,685,429	254,922	621,206	1,266			
	SG	325,263,098	4,998,325	84,642,021	25,669,890	143,107,625	19,182,293	47,582,536	92,176			
	SO	337,807,349	7,487,158	91,865,372	25,981,315	147,266,061	19,452,629	45,733,767	68,384			
	CN	15,121,106	362,368	4,723,952	1,048,151	7,229,309	635,060	1,122,267	0			
	DEU	0	0	0	0	0	0	0	0			
	SSGCT	0	0	0	0	0	0	0	0			
	SSGCH	0	0	0	0	0	0	0	0			
	Remove Capital L	(18,046,324)	(203,442)	(5,355,877)	(981,730)	(8,961,206)	(733,806)	(1,806,470)	(3,399)			
		1,371,464,106	34,230,282	399,358,386	100,520,568	549,003,156	94,745,209	193,507,577	158,427			
LESS ACCUMULATED DEPRECIATION												
	S	(284,204,552)	(8,783,724)	(98,751,963)	(25,985,023)	(95,695,742)	(19,347,081)	(35,641,020)	0			
	DGP	(733,304)	(11,269)	(190,825)	(57,873)	(322,636)	(43,246)	(107,248)	(208)			
	DGU	(3,023,369)	(46,460)	(786,760)	(238,605)	(1,330,207)	(178,302)	(442,177)	(857)			
	SE	(1,815,595)	(26,405)	(455,741)	(136,492)	(787,173)	(119,060)	(290,132)	(591)			
	SG	(130,423,218)	(2,004,216)	(33,939,555)	(10,293,051)	(57,382,953)	(7,691,670)	(19,074,829)	(36,961)			
	SO	(114,501,993)	(2,537,821)	(31,138,364)	(8,806,535)	(49,916,787)	(6,593,595)	(15,462,718)	(23,179)			
	CN	(5,443,176)	(130,442)	(1,700,491)	(377,305)	(2,602,350)	(228,604)	(403,985)	0			
	SSGCT	(132,826)	(2,041)	(34,565)	(10,483)	(58,440)	(7,833)	(19,426)	(38)			
	SSGCH	(2,912,078)	(44,750)	(757,799)	(229,822)	(1,281,241)	(171,739)	(425,901)	(825)			
		(543,190,112)	(13,587,129)	(167,756,063)	(46,135,189)	(209,377,529)	(34,381,131)	(71,867,436)	(62,659)			
TOTAL NET GENERAL PLANT		828,273,993	20,643,153	231,602,323	54,385,379	339,625,627	60,364,078	121,640,141	95,769			
SNPG												
SYSTEM NET GENERAL PLANT		100.0000%	2.4923%	27.9620%	6.5661%	41.0040%	7.2879%	14.1748%	0.0116%			
MINING:		TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC			
GENERAL MINING PLANT												
	SE	79,104,519	1,150,470	19,856,411	5,946,871	34,296,721	5,187,402	12,640,883	25,761			
LESS ACCUMULATED DEPRECIATION												
	SE	0	0	0	0	0	0	0	0			
		79,104,519	1,150,470	19,856,411	5,946,871	34,296,721	5,187,402	12,640,883	25,761			
SNPM												
SYSTEM NET PLANT MINING		100.0000%	1.4544%	25.1015%	7.5177%	43.3562%	6.5577%	15.9800%	0.0326%			
INTANGIBLE:		TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC			
INTANGIBLE PLANT												
	S	23,981,472	1,105,167	4,928,702	2,036,363	6,140,225	4,369,593	5,401,422	0			
	DGP	0	0	0	0	0	0	0	0			
	DGU	0	0	0	0	0	0	0	0			
	SE	(1,106,269)	(16,089)	(277,690)	(83,166)	(479,636)	(72,545)	(176,781)	(360)			
	CN	183,528,366	4,398,141	57,335,694	12,721,647	87,743,803	7,707,864	13,621,218	0			
	SG	303,216,540	4,659,535	78,904,926	23,929,967	133,407,691	17,882,103	44,278,054	85,929			
	SO	413,459,279	9,163,907	112,438,615	31,799,828	180,246,284	23,809,044	56,804,814	83,699			
	SSGCT	0	0	0	0	0	0	0	0			
	SSGCH	0	0	0	0	0	0	0	0			
		923,079,388	19,310,661	253,330,246	70,404,639	407,058,367	53,696,059	119,928,726	169,267			
LESS ACCUMULATED AMORTIZATION												
	S	(1,349,626)	(7,442)	(122,925)	(10,583)	(101,675)	(975,380)	(131,621)	0			
	DGP	0	0	0	0	0	0	0	0			
	DGU	(522,295)	(8,026)	(135,915)	(41,220)	(229,797)	(30,802)	(76,387)	(148)			
	SE	1,106,269	16,089	277,690	83,166	479,636	72,545	176,781	360			
	CN	(159,953,717)	(3,833,189)	(49,970,789)	(11,087,521)	(76,472,905)	(6,717,771)	(11,871,540)	0			
	SG	(144,152,630)	(2,215,197)	(37,512,309)	(11,376,582)	(63,423,551)	(8,501,358)	(21,081,442)	(40,851)			
	SO	(305,462,840)	(6,770,275)	(83,069,411)	(23,493,646)	(133,165,573)	(17,590,071)	(41,269,734)	(61,837)			
	SSGCT	0	0	0	0	0	0	0	0			
	SSGCH	(26,408)	(406)	(6,872)	(2,084)	(11,619)	(1,557)	(3,862)	(7)			
		(610,361,247)	(12,818,446)	(170,540,532)	(45,928,469)	(272,925,483)	(33,744,394)	(74,257,805)	(102,483)			

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TOTAL NET INTANGIBLE PLANT		312,718,140	6,492,215	82,789,715	24,476,170	134,132,883	19,951,665	45,670,921	66,784			
SNPI												
SYSTEM NET INTANGIBLE PLANT		100.0000%	2.0761%	26.4742%	7.8269%	42.8926%	6.3801%	14.3022%	0.0214%			
GROSS PLANT:		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**Non-Utility**	
PRODUCTION PLANT		13,578,829,578	208,664,116	3,533,667,790	1,071,635,965	5,974,286,493	800,799,475	1,982,755,231	3,848,069	0	0	
TRANSMISSION PLANT		7,626,615,097	117,198,360	1,984,646,024	601,895,430	3,355,519,835	449,777,312	1,119,511,773	2,161,308	0	0	
DISTRIBUTION PLANT		7,852,239,797	316,089,799	2,356,767,630	567,031,645	3,382,226,861	405,767,171	824,356,691	0	0	0	
GENERAL PLANT		1,450,568,624	35,380,752	419,214,797	106,467,439	583,299,877	99,932,610	206,148,460	184,189	0	0	
INTANGIBLE PLANT		923,079,388	19,310,661	253,330,246	70,404,639	407,058,367	53,696,059	119,928,726	169,267	0	0	
TOTAL GROSS PLANT		31,431,332,484	696,643,688	8,547,626,489	2,417,435,118	13,702,391,432	1,809,972,628	4,252,700,881	6,362,832	0	0	
GPS												
GROSS PLANT-SYSTEM FACTOR		100.0000%	2.2164%	27.1946%	7.6912%	43.5947%	5.7585%	13.5013%	0.0202%	0.0000%	0.0000%	
ACCUMULATED DEPRECIATION AND AMORTIZATION												
PRODUCTION PLANT		(4,232,662,387)	(61,703,798)	(1,044,896,854)	(316,892,097)	(1,989,547,812)	(235,576,995)	(585,947,860)	(1,137,907)	3,600,961	0	
TRANSMISSION PLANT		(2,013,271,856)	(30,937,992)	(523,906,338)	(158,888,198)	(885,789,247)	(118,732,097)	(294,500,592)	(570,541)	0	0	
DISTRIBUTION PLANT		(3,122,504,624)	(150,523,501)	(1,078,675,583)	(275,084,470)	(1,101,632,566)	(162,030,813)	(354,557,691)	0	0	0	
GENERAL PLANT		(543,190,112)	(13,587,129)	(167,756,063)	(46,135,189)	(209,377,529)	(34,381,131)	(71,867,436)	(62,659)	0	0	
INTANGIBLE PLANT		(610,361,247)	(12,818,446)	(170,540,532)	(45,928,469)	(272,925,483)	(33,744,394)	(74,257,805)	(102,483)	0	0	
		(10,521,990,226)	(269,570,867)	(2,985,775,370)	(842,928,423)	(4,459,272,638)	(584,465,431)	(1,381,131,384)	(1,873,591)	3,600,961	0	
NET PLANT		20,909,342,257	427,072,821	5,561,851,119	1,574,506,695	9,243,118,795	1,225,507,197	2,871,569,497	4,489,241	3,600,961	0	
SNP												
SYSTEM NET PLANT FACTOR (SNP)		100.0000%	2.0425%	26.5998%	7.5302%	44.2057%	5.8611%	13.6880%	0.0215%	0.0172%	0.0000%	
NON-REGULATED RELATED INTEREST PERCENTAGE		0.0000%										
INT												
INTEREST FACTOR SNP - NON-REGULATED		100.0000%	2.0425%	26.5998%	7.5302%	44.2057%	5.8611%	13.6880%	0.0215%	0.0172%	0.0000%	
TOTAL GROSS PLANT (LESS SO FACTOR)		30,681,774,762	680,030,499	8,343,787,232	2,359,785,409	13,375,624,080	1,766,809,362	4,150,393,025	6,211,095	0	0	
SO												
SYSTEM OVERHEAD FACTOR (SO)		100.0000%	2.2164%	27.1946%	7.6912%	43.5947%	5.7585%	13.5013%	0.0202%	0.0000%	0.0000%	
IBT												
INCOME BEFORE TAXES		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**Other**	**Non-Utility**	
INCOME BEFORE STATE TAXES		189,262,878	9,620,212	66,230,605	(18,016,878)	84,780,344	13,166,117	41,379,369	(265,791)	(7,141,815)	(0)	
Interest Synchronization		(7,196,941)	(146,997)	(1,914,375)	(541,941)	(3,181,457)	(421,816)	(985,114)	(1,545)	(1,239)	-	
		182,065,937	9,473,215	64,316,231	(18,558,819)	81,598,887	12,744,300	40,394,255	(267,336)	(7,143,054)	(0)	
INCOME BEFORE TAXES (FACTOR)		100.0000%	5.2032%	35.3258%	-10.1935%	44.8183%	6.9998%	24.6781%	-0.1468%	-3.9233%	0.0000%	

See Calculation of EXCTAX

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DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
DITEXP:		TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility	
Pacific Power												
Production	S	0										
Transmission	S	0										
Distribution	S	0										
General	S	0										
Mining Plant	S	0										
Non-Regulated	NUTIL	0										
Total Pacific Power		0	0	0	0	0	0	0	0	0	0	
Rocky Mountain Power												
Production	S	0										
Transmission	S	0										
Distribution	S	0										
General	S	0										
Mining Plant	S	0										
Non-Regulated	NUTIL	0										
Total Rocky Mountain Power		0	0	0	0	0	0	0	0	0	0	
PC (Post Merger)												
Prod / Other Prod	S	0										
Cholla Unit 4	S	0										
Gadsby Unit 4, 5 & 6	S	0										
Hydro-PPL	S	0										
Hydro-UPL	S	0										
Transmission	S	0										
Distribution	S	0										
General/ Intangibles	S	0										
Mining	S	0										
WCA - CAEE 2007+	S	0										
WCA - CAGE 2007+	S	0										
WCA - CAGW 2007+	S	0										
WCA_CAGW 2007+ -Marengo	S	0										
WCA CAGW 2007+ -Goodnoe	S	0										
WCA - General 2007+	S	0										
WCA - JBG 2007+	S	0										
Non-Regulated	NUTIL	0										
Total PC (Post Merger)		0	0	0	0	0	0	0	0	0	0	
Total Deferred Taxes		0	0	0	0	0	0	0	0	0	0	
Percentage of Total (DITEXP)		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	

Utah General Rate Case
December 2021
13 MONTH AVERAGE FACTORS

DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
DITBAL:		TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility	
Pacific Power												
Production	S	5,194,919	611,739	5,338,837	2,407,688	(4,420,617)	(128,995)	1,389,828	(3,561)		0	
Transmission	S	8,659,044	341,936	4,807,776	1,327,269	268,148	(13,756)	1,927,755	(84)		0	
Distribution	S	(535,900)	826,166	134,988	1,311,916	(2,614,148)	(9,445)	(185,377)	0		0	
General	S	(876,235)	(7,028)	(309,852)	(25,792)	(369,774)	(19,205)	(144,353)	(231)		0	
Mining Plant	S	4,407	67	1,103	336	1,870	274	749	8		0	
Malin	S	(2,553,878)	0	0	0	0	0	0	0		(2,553,878)	
Non-Regulated Plant	NUTIL	239,736	0	0	0	0	0	0	0		239,736	
Total Pacific Power		10,132,093	1,772,880	9,972,852	5,021,417	(7,134,521)	(171,127)	2,988,602	(3,868)	0	(2,314,142)	
Rocky Mountain Power												
Production	S	11,882,458	(38,004)	(3,509,113)	(195,225)	14,155,329	2,285,734	(963,877)	147,614		0	
Transmission	S	19,962,447	1,968	(111,664)	10,964	17,238,407	2,099,326	629,560	93,886		0	
Distribution	S	18,415,994	297,706	1,877,278	586,765	12,800,298	1,629,419	1,224,528	0		0	
General	S	(876,914)	(11,226)	(243,778)	(40,991)	(403,328)	(53,354)	(123,853)	(384)		0	
Mining Plant	S	9,054	137	2,264	690	3,847	564	1,536	16		0	
Non-Regulated Plant	NUTIL	0						0				
Total Rocky Mountain Power		49,393,039	250,581	(1,985,013)	362,203	43,794,553	5,961,689	767,894	241,132	0	0	
PacifiCorp												
Prod / Other Prod	S	226,980,776	4,032,955	64,164,705	18,365,265	93,039,883	12,581,573	34,030,310	766,085	0	0	
Cholla Unit 4	S	(18,791,242)	(331,331)	(5,350,501)	0	(8,214,437)	(1,186,048)	(2,837,974)	(44,716)		(826,235)	
Gadsby Unit 4, 5 & 6	S	4,322,427	67,465	1,105,005	0	1,875,398	247,543	647,342	11,976		367,698	
Hydro-PPL	S	21,628,360	419,586	6,415,124	1,818,947	8,577,757	1,139,707	3,188,190	69,049		0	
Hydro-UPL	S	6,305,738	127,363	1,881,739	549,129	2,493,383	327,990	907,783	18,351		0	
Transmission	S	176,749,505	3,204,428	51,439,031	14,409,527	71,513,505	9,523,948	26,116,218	542,848		0	
Distribution	S	653,171,964	22,898,524	185,149,651	42,105,035	306,683,990	32,029,218	64,300,941	0		4,605	
General/ Intangibles	S	12,225,329	312,636	4,376,661	767,066	4,166,213	669,412	1,884,853	48,488		0	
Mining	S	2,017	30	506	154	864	129	333	1		0	
WCA - CAEE 2007+	S	(2,206)	(5)	(503)	0	(814)	(133)	(354)	(1)		(396)	
WCA - CAGE 2007+	S	1,269,610,095	20,188,632	332,689,139	0	538,629,692	71,563,799	195,996,257	3,623,512		106,919,064	
WCA - CAGW 2007+	S	318,072,033	5,180,455	85,704,060	69,317,814	137,552,105	18,413,632	49,528,692	866,341		(48,491,066)	
Utah Extra Book Depreciation	S	(43,905,412)	0	0	0	(43,905,412)	0	0	0		0	
WCA CAGW 2007+ -Goodnoe	S	0	0	0	0	0	0	0	0		0	
WCA - General 2007+	S	137,547,091	3,005,337	37,709,154	9,182,681	58,886,628	7,776,177	19,317,915	158,374		1,510,825	
WCA - JBG 2007+	S	106,021,297	1,673,892	28,112,056	23,154,834	45,857,308	6,122,361	16,403,712	223,036		(15,525,902)	
OREGON EXTRA BOOK DEPR	S	(83,050,415)	0	(83,050,415)	0	0	0	0	0		0	
Non Regulated	NUTIL	(1,101,878)	0	0	0	0	0	0	0		(1,101,878)	
Total PC (Post Merger)		2,785,785,479	60,779,967	710,345,412	179,670,452	1,217,156,063	159,209,308	409,484,218	6,283,344	0	42,856,715	
Total Deferred Taxes		2,845,310,611	62,803,428	718,333,251	185,054,072	1,253,816,095	164,999,870	413,240,714	6,520,608	0	40,542,573	
Percentage of Total (DITBAL)		100.0000%	2.2073%	25.2462%	6.5038%	44.0661%	5.7990%	14.5236%	0.2292%	0.0000%	1.4249%	

OPRV-WY

	Pacific Division	Utah Division	Combined Total
Total Sales to Ultimate Customers	0	0	0
Less: Uncollectibles (net)	0	0	0
Total Interstate Revenues	0	0	0
	0.0000%	0.0000%	0.0000%

Utah General Rate Case
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13 MONTH AVERAGE FACTORS

DESCRIPTION	2020 PROTOCOL FACTOR	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.

OPRV-ID

	Pacific Division	Utah Division	Combined Total
Total Sales to Ultimate Customers	0	0	0
Less: Interstate Sales for Resale			
Montana Power	0	0	0
Portland General Electric	0	0	0
Puget Sound Power & Light	0	0	0
Washington Water Power Co.	0	0	0
Less: Uncollectibles (net)	0	0	0
Total Interstate Revenues	0	0	0
	0.0000%	0.0000%	0.0000%

BADDEBT

	TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	OTHER	Non-Utility
Account 904 Balance	12,439,916	700,981	4,739,172	1,281,547	4,053,793	630,184	1,115,925	0	0	0
Bad Debts Expense Allocation Factor - BADDEBT	100.0000%	5.6349%	38.0965%	10.3019%	32.5870%	5.0658%	8.2698%	0.0000%	0.0000%	0.0000%

Customer Factors	TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility
Total Electric Customers	1,985,058	47,571	620,148	137,598	949,044	83,369	147,328	0	0	0
CN										
Customer System factor - CN	100.0000%	2.3964%	31.2408%	6.9317%	47.8094%	4.1998%	7.4219%	0.0000%	0.0000%	0.0000%
Pacific Power Customers	936,295	47,571	620,148	137,598	0	0	130,978	0	0	0
CNP										
Customer Service Pacific Power factor - CNP	100.0000%	5.08%	66.23%	14.70%	0.00%	0.00%	13.99%	0.00%	0.00%	0.00%
Rocky Mountain Power Customers	1,048,763	0	0	0	949,044	83,369	16,350	0	0	0
CNU										
Customer Service R.M.P. factor - CNU	100.0000%	0.00%	0.00%	0.00%	90.49%	7.95%	1.56%	0.00%	0.00%	0.00%

CIAC	TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility
TOTAL NET DISTRIBUTION PLANT	4,729,735,173	165,566,298	1,278,092,047	291,947,176	2,280,594,295	243,736,358	469,798,999	0	0	0
CIAC FACTOR: Same as (SNPD Factor)	100.00%	3.50%	27.02%	6.17%	48.22%	5.15%	9.88%	0.00%	0.00%	0.00%

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DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
IDSIT		Total Company	Idaho - PPL	Idaho - UPL	Idaho Total							
	Payroll	0	0	0	0							
Idaho State Income Tax Allocation			0.00%	0.00%	0.00%							
	Property	0	0	0	0							
			0.00%	0.00%	0.00%							
	Sales	0	0	0	0							
			0.00%	0.00%	0.00%							
	Average		0.00%	0.00%								
		Idaho - PPL Factor	0.00%	0.00%								
		Idaho - UPL Factor	0.00%	0.00%								
			0.00%	0.00%								
EXCTAX												
Excise Tax (Superfund)		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**Other**	**Non-Utility**	
Total Taxable Income		180,670,343	9,183,454	63,223,736	(17,198,912)	80,931,317	12,568,375	39,500,746	(253,724)	(6,817,577)	(0)	
Less Other Electric Items:												
419	OTH	0	0	0	0	0	0	0	0	0	0	
432	OTH	0	0	0	0	0	0	0	0	0	0	
40910	OTH	0	0	0	0	0	0	0	0	0	0	
SCHMDT	OTH	0	0	0	0	0	0	0	0	0	0	
SCHMDT (Steam)	OTH											
Total Taxable Income Excluding Other		180,670,343	9,183,454	63,223,736	(17,198,912)	80,931,317	12,568,375	39,500,746	(253,724)	(6,817,577)	(0)	
Excise Tax (Superfund) Factor - EXCTAX		100.0000%	5.0830%	34.9940%	-9.5195%	44.7950%	6.9565%	24.2152%	-0.1404%	-3.7735%	0.0000%	
Trojan Allocators		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**Other**	**Non-Utility**	
Premerger												
Dec 1991 Plant		16,918,976										
Dec 1992 Plant		17,094,202										
Average	SG	17,006,589	261,341	4,425,562	1,342,167	7,482,474	1,002,958	2,487,268	4,819	0	0	
Dec 1991 Reserve		(7,851,432)										
Dec 1992 Reserve		(8,434,030)										
Average	SG	(8,142,731)	(125,130)	(2,118,953)	(642,627)	(3,582,598)	(480,215)	(1,190,900)	(2,308)	0	0	
Postmerger												
Dec 1991 Plant		4,284,960										
Dec 1992 Plant		3,485,613										
Average	SG	3,885,287	59,705	1,011,054	306,628	1,709,429	229,134	568,236	1,101	0	0	
Dec 1991 Reserve		(129,394)										
Dec 1992 Reserve		(240,609)										
Average	SG	(185,002)	(2,843)	(48,142)	(14,600)	(81,396)	(10,910)	(27,057)	(52)	0	0	
Net Plant		12,564,143	193,073	3,269,521	991,567	5,527,909	740,967	1,837,546	3,561	0	0	
Division Net Plant Nuclear Pacific Power	**DNPPNP**	100.0000%	1.5367%	26.0226%	7.8920%	43.9975%	5.8975%	14.6253%	0.0283%	0.0000%	0.0000%	
Division Net Plant Nuclear Rocky Mountain Power	**DNPPNP**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
System Net Nuclear Plant	**SNNP**	100.0000%	1.5367%	26.0226%	7.8920%	43.9975%	5.8975%	14.6253%	0.0283%	0.0000%	0.0000%	

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DESCRIPTION		2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
Account 182.22			TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility	
Pre-merger	(101)	SG	17,094,202	262,687	4,448,361	1,349,081	7,521,021	1,008,125	2,500,082	4,844	0	0	
		(108) SG	(8,434,030)	(129,606)	(2,194,757)	(665,617)	(3,710,762)	(497,394)	(1,233,504)	(2,390)	0	0	
Post-merger	(101)	SG	3,485,613	53,563	907,048	275,086	1,533,583	205,563	509,782	988	0	0	
		(108) SG	(240,609)	(3,697)	(62,613)	(18,989)	(105,862)	(14,190)	(35,190)	(68)	0	0	
		(107) SG	1,778,549	27,331	462,825	140,364	782,517	104,889	260,118	504	0	0	
		(120) SE	1,975,759	28,735	495,945	148,532	856,614	129,563	315,726	643	0	0	
		(228) SG	7,220,849	110,963	1,879,055	569,872	3,176,993	425,847	1,056,072	2,046	0	0	
		(228) SG	1,472,376	22,626	383,151	116,200	647,809	86,833	215,340	417	0	0	
		(228) SNNP	3,531,000	54,261	918,859	278,668	1,553,552	208,240	516,420	1,001	0	0	
		(228) SE	1,743,025	25,350	437,525	131,036	755,710	114,302	278,535	568	0	0	
Total Acct 182.22			29,626,734	452,213	7,675,401	2,324,234	13,011,174	1,771,779	4,383,381	8,553	0	0	
Revised Study	(228)	SNNP	112,680	1,732	29,322	8,893	49,576	6,645	16,480	32	0	0	
		(228) SE	941,950	13,699	236,443	70,813	408,394	61,770	150,523	307	0	0	
December 1993 Adj.			1,054,630	15,431	265,766	79,706	457,970	68,415	167,003	339	0	0	
Adjusted Acct 182.22			30,681,364	467,644	7,941,167	2,403,940	13,469,144	1,840,194	4,550,384	8,892	0	0	
TROJP			100.0000%	1.5242%	25.8827%	7.8352%	43.9001%	5.9978%	14.8311%	0.0290%	0.0000%	0.0000%	
Trojan Plant Allocator													
Account 228.42			TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility	
Plant - Premerger		SG	7,220,849	110,963	1,879,055	569,872	3,176,993	425,847	1,056,072	2,046	0	0	
- Postmerger		SG	1,472,376	22,626	383,151	116,200	647,809	86,833	215,340	417	0	0	
Storage Facility		SE	1,743,025	25,350	437,525	131,036	755,710	114,302	278,535	568	0	0	
Transition Costs		SNNP	3,531,000	54,261	918,859	278,668	1,553,552	208,240	516,420	1,001	0	0	
Total Acct 228.42			13,967,250	213,200	3,618,590	1,095,777	6,134,063	835,222	2,066,367	4,032	0	0	
Transition Costs		SNNP	112,680	1,732	29,322	8,893	49,576	6,645	16,480	32	0	0	
Storage Facility		SE	941,950	13,699	236,443	70,813	408,394	61,770	150,523	307	0	0	
December 1993 Adj.			1,054,630	15,431	265,766	79,706	457,970	68,415	167,003	339	0	0	
Adjusted Acct 228.42			15,021,880	228,631	3,884,356	1,175,483	6,592,033	903,637	2,233,370	4,371	0	0	
TROJD			100.0000%	1.5220%	25.8580%	7.8251%	43.8829%	6.0155%	14.8674%	0.0291%	0.0000%	0.0000%	
Trojan Decommissioning Allocator													
SCHMA			TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility	
Amortization Expense :													
Amortization of Limited Term Plant		Acct 404	51,246,077	889,509	12,108,425	3,250,119	23,220,173	2,275,078	5,271,094	6,925	4,263,005	0	
Amortization of Other Electric Plant		Acct 405	0	0	0	0	0	0	0	0	0	0	
Amortization of Plant Acquisitions		Acct 406	376,987	1,158	19,608	5,947	334,788	4,444	699,318	21	0	0	
Amort of Prop. Losses, Unrecovered Plant, etc.		Acct 407	3,090,571	595,633	10,085,524	3,059,956	(19,172,706)	2,275,858	6,353,402	10,984	124,290	0	
Total Amortization Expense :			54,713,635	1,486,300	22,213,557	6,316,022	4,382,255	4,555,380	12,323,814	17,930	4,387,295	0	
Schedule M Amortization Factor			100.0000%	2.7165%	40.5997%	11.5438%	8.0094%	8.3259%	20.0727%	0.0328%	8.0187%	0.0000%	

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DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
SCHMD		TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility	
Depreciation Expense :												
Steam	Acct 403.1	331,311,576	5,091,272	86,215,994	26,147,238	145,768,805	19,539,000	48,557,319	93,890	0	0	
Nuclear	Acct 403.2	0	0	0	0	0	0	0	0	0	0	
Hydro	Acct 403.3	38,042,673	584,603	9,899,705	3,002,343	16,737,824	2,243,555	5,600,294	10,781	0	0	
Other	Acct 403.4	245,676,242	3,775,312	63,931,426	19,388,865	108,091,400	14,488,682	35,624,780	69,622	0	0	
Transmission	Acct 403.5	130,721,631	2,008,802	34,017,210	10,316,602	57,514,247	7,709,269	19,190,133	37,045	0	0	
Distribution	Acct 403.6	203,548,449	8,482,527	60,954,564	15,534,439	85,908,600	10,564,938	22,103,381	0	0	0	
General	Acct 403.7&8	47,059,702	1,047,110	13,748,541	3,455,770	19,141,404	2,954,524	6,707,764	6,818	0	0	
Mining	Acct 403.9	0	0	0	0	0	0	0	0	0	0	
Experimental	Acct 403.4	0	0	0	0	0	0	0	0	0	0	
Total Depreciation Expense :		996,360,273	20,989,625	268,767,439	77,845,257	433,162,280	57,499,968	137,783,670	218,157	0	0	
Schedule M Depreciation Factor		100.0000%	2.1066%	26.9749%	7.8130%	43.4745%	5.7710%	13.8187%	0.0219%	0.0000%	0.0000%	

Tax Depreciation by Function	TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility
Current Total M Difference	828,627,928	16,868,132	218,346,458	53,698,579	372,474,934	46,815,036	111,705,790	168,677	8,550,322	
Tax Depr factor	100.0000%	2.0357%	26.3504%	6.4804%	44.9508%	5.6497%	13.4808%	0.0204%	1.0319%	0.0000%

Utah General Rate Case
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COINCIDENTAL PEAKS (MW)

			FORECAST LOADS (CP)							
			Non-FERC						FERC	
Month	Day	Hour	CA	OR	WA	UT	ID	WY	UT FERC	TOTAL
Jan-21	14	8	158	2,638	840	3,439	452	1,274	2	8,803
Feb-21	9	8	148	2,448	701	3,316	433	1,235	2	8,281
Mar-21	11	8	143	2,364	670	3,219	429	1,205	2	8,031
Apr-21	7	8	125	2,225	582	3,057	419	1,143	2	7,554
May-21	18	15	116	1,914	575	3,840	527	1,145	2	8,118
Jun-21	24	15	133	2,051	684	4,705	712	1,244	2	9,531
Jul-21	19	16	144	2,376	755	4,944	794	1,270	3	10,286
Aug-21	26	16	136	2,449	746	4,796	613	1,221	3	9,963
Sep-21	9	16	121	2,138	660	4,358	514	1,144	2	8,938
Oct-21	4	18	110	1,890	602	3,619	418	1,153	2	7,793
Nov-21	24	18	131	2,206	704	3,588	454	1,258	2	8,343
Dec-21	15	18	145	2,402	734	3,779	476	1,300	3	8,838
			1,610	27,103	8,252	46,659	6,239	14,590	28	104,481

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			Adjustments for Curtailments, Buy-Throughs and Load No Longer Served (Reductions to Load)							
			Non-FERC						FERC	
Month	Day	Hour	CA	OR	WA	UT	ID	WY	UT FERC	TOTAL
Jan-21	14	8	-	-	-	(115)	-	-	-	(115)
Feb-21	9	8	-	-	-	(23)	-	-	-	(23)
Mar-21	11	8	-	-	-	(25)	-	-	-	(25)
Apr-21	7	8	-	-	-	(26)	-	-	-	(26)
May-21	18	15	-	-	-	(28)	-	-	-	(28)
Jun-21	24	15	-	-	-	(254)	(170)	-	-	(424)
Jul-21	19	16	-	-	-	(241)	(146)	-	-	(387)
Aug-21	26	16	-	-	-	(253)	(79)	-	-	(332)
Sep-21	9	16	-	-	-	(95)	-	-	-	(95)
Oct-21	4	18	-	-	-	-	-	-	-	-
Nov-21	24	18	-	-	-	-	-	-	-	-
Dec-21	15	18	-	-	-	(91)	-	-	-	(91)
			-	-	-	(1,150)	(395)	-	-	(1,545)

(=)

			COINCIDENTAL PEAK SERVED FROM COMPANY RESOURES							
			Non-FERC						FERC	
Month	Day	Hour	CA	OR	WA	UT	ID	WY	UT FERC	TOTAL
Jan-21	14	8	158	2,638	840	3,324	452	1,274	2	8,688
Feb-21	9	8	148	2,448	701	3,293	433	1,235	2	8,258
Mar-21	11	8	143	2,364	670	3,194	429	1,205	2	8,006
Apr-21	7	8	125	2,225	582	3,031	419	1,143	2	7,529
May-21	18	15	116	1,914	575	3,812	527	1,145	2	8,091
Jun-21	24	15	133	2,051	684	4,451	542	1,244	2	9,107
Jul-21	19	16	144	2,376	755	4,703	648	1,270	3	9,899
Aug-21	26	16	136	2,449	746	4,543	534	1,221	3	9,631
Sep-21	9	16	121	2,138	660	4,263	514	1,144	2	8,843
Oct-21	4	18	110	1,890	602	3,619	418	1,153	2	7,793
Nov-21	24	18	131	2,206	704	3,588	454	1,258	2	8,343
Dec-21	15	18	145	2,402	734	3,688	476	1,300	3	8,747
			1,610	27,103	8,252	45,509	5,844	14,590	28	102,936

(+)

			Adjustments for Ancillary Services Contracts including Reserves (Additions to Load)							
			Non-FERC						FERC	
Month	Day	Hour	CA	OR	WA	UT	ID	WY	UT FERC	TOTAL
Jan-21	14	8	-	-	-	-	-	-	-	-
Feb-21	9	8	-	-	-	-	-	-	-	-
Mar-21	11	8	-	-	-	-	-	-	-	-
Apr-21	7	8	-	-	-	-	-	-	-	-
May-21	18	15	-	-	-	-	-	-	-	-
Jun-21	24	15	-	-	-	-	-	-	-	-
Jul-21	19	16	-	-	-	-	-	-	-	-
Aug-21	26	16	-	-	-	-	-	-	-	-
Sep-21	9	16	-	-	-	-	-	-	-	-
Oct-21	4	18	-	-	-	-	-	-	-	-
Nov-21	24	18	-	-	-	-	-	-	-	-
Dec-21	15	18	-	-	-	-	-	-	-	-
			-	-	-	-	-	-	-	-

(=)

			LOADS FOR JURISDICTIONAL ALLOCATION (CP)							
			Non-FERC						FERC	
Month	Day	Hour	CA	OR	WA	UT	ID	WY	UT FERC	TOTAL
Jan-19	14	8	158	2,638	840	3,324	452	1,274	2	8,688
Feb-19	9	8	148	2,448	701	3,293	433	1,235	2	8,258
Mar-19	11	8	143	2,364	670	3,194	429	1,205	2	8,006
Apr-19	7	8	125	2,225	582	3,031	419	1,143	2	7,529
May-19	18	15	116	1,914	575	3,812	527	1,145	2	8,091
Jun-19	24	15	133	2,051	684	4,451	542	1,244	2	9,107
Jul-18	19	16	144	2,376	755	4,703	648	1,270	3	9,899
Aug-18	26	16	136	2,449	746	4,543	534	1,221	3	9,631
Sep-18	9	16	121	2,138	660	4,263	514	1,144	2	8,843
Oct-18	4	18	110	1,890	602	3,619	418	1,153	2	7,793
Nov-18	24	18	131	2,206	704	3,588	454	1,258	2	8,343
Dec-18	15	18	145	2,402	734	3,688	476	1,300	3	8,747
			1,610	27,103	8,252	45,509	5,844	14,590	28	102,936
	Factors:	SG	1.5367%	26.0226%	7.8920%	43.9975%	5.8975%	14.6253%	0.0283%	100.00%
		SC	1.5641%	26.3297%	8.0168%	44.2113%	5.6774%	14.1738%	0.0269%	100.00%

Utah General Rate Case
December 2021
ENERGY (MWh)

		FORECAST LOADS (MWh)							
		Non-FERC						FERC	
Year	Month	CA	OR	WA	UT	ID	WY	UT FERC	TOTAL
2021	Jan	80,880	1,445,050	443,650	2,238,808	303,070	875,880	1,746	5,389,084
2021	Feb	68,410	1,246,380	371,420	1,959,804	263,240	786,720	1,502	4,697,475
2021	Mar	70,110	1,295,980	365,150	2,057,684	292,240	827,140	1,568	4,909,873
2021	Apr	67,640	1,191,840	332,720	1,979,912	284,450	778,150	1,414	4,636,126
2021	May	73,560	1,182,260	341,350	2,063,253	342,760	789,460	1,458	4,794,102
2021	Jun	77,460	1,171,530	347,030	2,304,782	402,830	777,680	1,661	5,082,973
2021	Jul	83,620	1,308,420	401,760	2,721,099	490,400	829,390	1,989	5,836,678
2021	Aug	79,230	1,289,920	397,670	2,617,707	402,350	820,020	1,887	5,608,784
2021	Sep	68,350	1,162,130	356,060	2,197,786	314,430	768,290	1,533	4,868,580
2021	Oct	64,420	1,183,660	364,900	2,092,862	286,680	798,380	1,434	4,792,336
2021	Nov	68,130	1,279,230	389,850	2,075,300	286,810	793,990	1,634	4,894,944
2021	Dec	80,020	1,463,450	446,690	2,257,555	306,860	844,080	1,918	5,400,573
		881,830	15,219,850	4,558,250	26,566,551	3,976,120	9,689,180	19,746	60,911,527

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		Adjustments for Curtailments, Buy-Throughs and Load No Longer Served (Reductions to Load)							
		Non-FERC						FERC	
Year	Month	CA	OR	WA	UT	ID	WY	UT FERC	TOTAL
2021	Jan	-	-	-	(19,953)	-	-	-	(19,953)
2021	Feb	-	-	-	(13,658)	-	-	-	(13,658)
2021	Mar	-	-	-	(21,443)	-	-	-	(21,443)
2021	Apr	-	-	-	(23,649)	-	-	-	(23,649)
2021	May	-	-	-	(27,259)	-	-	-	(27,259)
2021	Jun	-	-	-	(28,383)	-	-	-	(28,383)
2021	Jul	-	-	-	(32,194)	-	-	-	(32,194)
2021	Aug	-	-	-	(30,572)	-	-	-	(30,572)
2021	Sep	-	-	-	(31,295)	-	-	-	(31,295)
2021	Oct	-	-	-	(19,304)	-	-	-	(19,304)
2021	Nov	-	-	-	(13,605)	-	-	-	(13,605)
2021	Dec	-	-	-	(16,955)	-	-	-	(16,955)
		-	-	-	(278,269)	-	-	-	(278,269)

(=)

		LOADS SERVED FROM COMPANY RESOURES (NPC)							
		Non-FERC						FERC	
Year	Month	CA	OR	WA	UT	ID	WY	UT FERC	TOTAL
2021	Jan	80,880	1,445,050	443,650	2,218,855	303,070	875,880	1,746	5,369,131
2021	Feb	68,410	1,246,380	371,420	1,946,146	263,240	786,720	1,502	4,683,818
2021	Mar	70,110	1,295,980	365,150	2,036,242	292,240	827,140	1,568	4,888,430
2021	Apr	67,640	1,191,840	332,720	1,956,263	284,450	778,150	1,414	4,612,477
2021	May	73,560	1,182,260	341,350	2,035,995	342,760	789,460	1,458	4,766,843
2021	Jun	77,460	1,171,530	347,030	2,276,400	402,830	777,680	1,661	5,054,590
2021	Jul	83,620	1,308,420	401,760	2,688,904	490,400	829,390	1,989	5,804,483
2021	Aug	79,230	1,289,920	397,670	2,587,135	402,350	820,020	1,887	5,578,211
2021	Sep	68,350	1,162,130	356,060	2,166,491	314,430	768,290	1,533	4,837,284
2021	Oct	64,420	1,183,660	364,900	2,073,558	286,680	798,380	1,434	4,773,032
2021	Nov	68,130	1,279,230	389,850	2,061,695	286,810	793,990	1,634	4,881,339
2021	Dec	80,020	1,463,450	446,690	2,240,600	306,860	844,080	1,918	5,383,619
		881,830	15,219,850	4,558,250	26,288,282	3,976,120	9,689,180	19,746	60,633,258

(+)

		Adjustments for Ancillary Services Contracts including Reserves (Additions to Load)							
		Non-FERC						FERC	
Year	Month	CA	OR	WA	UT	ID	WY	UT FERC	TOTAL
2021	Jan	-	-	-	-	-	-	-	-
2021	Feb	-	-	-	-	-	-	-	-
2021	Mar	-	-	-	-	-	-	-	-
2021	Apr	-	-	-	-	-	-	-	-
2021	May	-	-	-	-	-	-	-	-
2021	Jun	-	-	-	-	-	-	-	-
2021	Jul	-	-	-	-	-	-	-	-
2021	Aug	-	-	-	-	-	-	-	-
2021	Sep	-	-	-	-	-	-	-	-
2021	Oct	-	-	-	-	-	-	-	-
2021	Nov	-	-	-	-	-	-	-	-
2021	Dec	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-

(=)

		LOADS FOR JURISDICTIONAL ALLOCATION (MWh)							
		Non-FERC						FERC	
Year	Month	CA	OR	WA	UT	ID	WY	UT FERC	TOTAL
2021	Jan	80,880	1,445,050	443,650	2,218,855	303,070	875,880	1,746	5,369,131
2021	Feb	68,410	1,246,380	371,420	1,946,146	263,240	786,720	1,502	4,683,818
2021	Mar	70,110	1,295,980	365,150	2,036,242	292,240	827,140	1,568	4,888,430
2021	Apr	67,640	1,191,840	332,720	1,956,263	284,450	778,150	1,414	4,612,477
2021	May	73,560	1,182,260	341,350	2,035,995	342,760	789,460	1,458	4,766,843
2021	Jun	77,460	1,171,530	347,030	2,276,400	402,830	777,680	1,661	5,054,590
2021	Jul	83,620	1,308,420	401,760	2,688,904	490,400	829,390	1,989	5,804,483
2021	Aug	79,230	1,289,920	397,670	2,587,135	402,350	820,020	1,887	5,578,211
2021	Sep	68,350	1,162,130	356,060	2,166,491	314,430	768,290	1,533	4,837,284
2021	Oct	64,420	1,183,660	364,900	2,073,558	286,680	798,380	1,434	4,773,032
2021	Nov	68,130	1,279,230	389,850	2,061,695	286,810	793,990	1,634	4,881,339
2021	Dec	80,020	1,463,450	446,690	2,240,600	306,860	844,080	1,918	5,383,619
		881,830	15,219,850	4,558,250	26,288,282	3,976,120	9,689,180	19,746	60,633,258
Factors:	SE	1.4544%	25.1015%	7.5177%	43.3562%	6.5577%	15.9800%	0.0326%	100.00%

Utah General Rate Case
December 2021

	CALIFORNIA	OREGON	WASHINGTON	UTAH	IDAHO	WYOMING	FERC	TOTAL	Page Ref.
Subtotal	881,830	15,219,850	4,558,250	26,288,282	3,976,120	9,689,180	19,746	60,633,258	9.14
System Energy Factor	1.4544%	25.1015%	7.5177%	43.3562%	6.5577%	15.9800%	0.0326%	100.00%	
Divisional Energy - Pacific	3.0995%	53.4958%	16.0217%	0.0000%	0.0000%	27.3830%	0.0000%	100.00%	
Divisional Energy - Utah	0.0000%	0.0000%	0.0000%	81.6845%	12.3548%	5.8993%	0.0614%	100.00%	
System Generation Factor	1.5367%	26.0226%	7.8920%	43.9975%	5.8975%	14.6253%	0.0283%	100.00%	
Divisional Generation - Pacific	3.2512%	55.0569%	16.6974%	0.0000%	0.0000%	24.9944%	0.0000%	100.00%	
Divisional Generation - Utah	0.0000%	0.0000%	0.0000%	83.4313%	11.1832%	5.3318%	0.0537%	100.00%	
System Capacity (kw)									
Accord	1,610.1	27,102.6	8,252.2	45,509.1	5,844.1	14,589.9	27.7	102,935.6	9.13
Modified Accord	1,610.1	27,102.6	8,252.2	45,509.1	5,844.1	14,589.9	27.7	102,935.6	9.13
Rolled-In	1,610.1	27,102.6	8,252.2	45,509.1	5,844.1	14,589.9	27.7	102,935.6	9.13
Rolled-In with Hydro Adj.	1,610.1	27,102.6	8,252.2	45,509.1	5,844.1	14,589.9	27.7	102,935.6	9.13
Rolled-In with Off-Sys Adj.	1,610.1	27,102.6	8,252.2	45,509.1	5,844.1	14,589.9	27.7	102,935.6	9.13
System Capacity Factor									
Accord	1.5641%	26.3297%	8.0168%	44.2113%	5.6774%	14.1738%	0.0269%	100.00%	
Modified Accord	1.5641%	26.3297%	8.0168%	44.2113%	5.6774%	14.1738%	0.0269%	100.00%	
Rolled-In	1.5641%	26.3297%	8.0168%	44.2113%	5.6774%	14.1738%	0.0269%	100.00%	
Rolled-In with Hydro Adj.	1.5641%	26.3297%	8.0168%	44.2113%	5.6774%	14.1738%	0.0269%	100.00%	
Rolled-In with Off-Sys Adj.	1.5641%	26.3297%	8.0168%	44.2113%	5.6774%	14.1738%	0.0269%	100.00%	
System Energy (kwh)									
Accord	881,830	15,219,850	4,558,250	26,288,282	3,976,120	9,689,180	19,746	60,633,258	
Modified Accord	881,830	15,219,850	4,558,250	26,288,282	3,976,120	9,689,180	19,746	60,633,258	
Rolled-In	881,830	15,219,850	4,558,250	26,288,282	3,976,120	9,689,180	19,746	60,633,258	
Rolled-In with Hydro Adj.	881,830	15,219,850	4,558,250	26,288,282	3,976,120	9,689,180	19,746	60,633,258	
Rolled-In with Off-Sys Adj.	881,830	15,219,850	4,558,250	26,288,282	3,976,120	9,689,180	19,746	60,633,258	
System Energy Factor									
Accord	1.4544%	25.1015%	7.5177%	43.3562%	6.5577%	15.9800%	0.0326%	100.00%	
Modified Accord	1.4544%	25.1015%	7.5177%	43.3562%	6.5577%	15.9800%	0.0326%	100.00%	
Rolled-In	1.4544%	25.1015%	7.5177%	43.3562%	6.5577%	15.9800%	0.0326%	100.00%	
Rolled-In with Hydro Adj.	1.4544%	25.1015%	7.5177%	43.3562%	6.5577%	15.9800%	0.0326%	100.00%	
Rolled-In with Off-Sys Adj.	1.4544%	25.1015%	7.5177%	43.3562%	6.5577%	15.9800%	0.0326%	100.00%	
System Generation Factor									
Accord	1.5367%	26.0226%	7.8920%	43.9975%	5.8975%	14.6253%	0.0283%	100.00%	
Modified Accord	1.5367%	26.0226%	7.8920%	43.9975%	5.8975%	14.6253%	0.0283%	100.00%	
Rolled-In	1.5367%	26.0226%	7.8920%	43.9975%	5.8975%	14.6253%	0.0283%	100.00%	
Rolled-In with Hydro Adj.	1.5367%	26.0226%	7.8920%	43.9975%	5.8975%	14.6253%	0.0283%	100.00%	
Rolled-In with Off-Sys Adj.	1.5367%	26.0226%	7.8920%	43.9975%	5.8975%	14.6253%	0.0283%	100.00%	

Utah General Rate Case
December 2021
2020 Protocol Adjustment

	Total	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC
2020 Protocol Baseline ECD	(10,164,458)	-	(11,000,000)	-	-	835,542	-	-
2020 Protocol Wyoming QF Adjustment	(5,000,000)	-	-	-	-	-	(5,000,000)	-
2020 Protocol Adjustment	**(15,164,458)**	**-**	**(11,000,000)**	**-**	**-**	**835,542**	**(5,000,000)**	**-**

REDACTED
Rocky Mountain Power
Exhibit RMP___(SRM-3R)
Docket No. 20-035-04
Witness: Steven R. McDougal

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Exhibit Accompanying Rebuttal Testimony of Steven R. McDougal

CONF Pages - Test Period Results of Operations - Twelve Months Ending December 2021

October 2020

REDACTED

Rocky Mountain Power
Utah General Rate Case - December 2021
Adjustment Summary
CONFIDENTIAL

		UTAH ALLOCATED UNADJUSTED RESULTS DECEMBER 2019	Tab 3 Revenue Adjustments	Tab 4 O&M Adjustments	Tab 5 Net Power Cost Adjustments	Tab 6 Depreciation & Amortization Adjustments
1	Operating Revenues:		[redacted]			[redacted]
2	General Business Revenues	1,988,715,510		-		
3	Interdepartmental	-		-		
4	Special Sales	78,282,917		-	19,971,538	
5	Other Operating Revenues	70,101,388		(2,716,081)		
6	Total Operating Revenues	2,137,099,816		(2,716,081)	19,971,538	
7						
8	Operating Expenses:					
9	Steam Production	451,142,931		4,095,700	(48,916,477)	
10	Nuclear Production	-		-		
11	Hydro Production	19,409,835		1,085,315		
12	Other Power Supply	462,939,589		3,078,293	(32,724,991)	
13	Transmission	96,044,207		1,718,141	394,121	
14	Distribution	85,455,009		6,529,192		
15	Customer Accounting	33,249,315		2,449,447		
16	Customer Service & Info	6,511,449		477,757		
17	Sales	-		-		
18	Administrative & General	50,747,835		4,769,224		
19						
20	Total O&M Expenses	1,205,500,169		24,203,069	(81,247,348)	
21						
22	Depreciation	305,190,671		-		
23	Amortization	20,768,321		-	63,742	
24	Taxes Other Than Income	71,685,583		-		
25	Income Taxes - Federal	78,802,378		(5,649,060)	20,130,118	
26	Income Taxes - State	20,624,126		(1,279,356)	4,558,914	
27	Income Taxes - Def Net	(11,875,493)		-	176,664	
28	Investment Tax Credit Adj.	(2,284,953)		-		
29	Misc Revenue & Expense	(1,588,348)		1,119,232		
30						
31	Total Operating Expenses:	1,686,822,455		18,393,885	(56,317,910)	
32						
33	Operating Rev For Return:	450,277,361		(21,109,966)	76,289,447	
34						
35	Rate Base:					
36	Electric Plant In Service	12,242,571,339		-	1,759,900	
37	Plant Held for Future Use	11,265,782		-		
38	Misc Deferred Debits	332,552,084		-		
39	Elec Plant Acq Adj	17,635,536		-		
40	Nuclear Fuel	1,950,836		-		
41	Prepayments	16,466,051		-		
42	Fuel Stock	72,830,126		-		
43	Material & Supplies	104,244,001		-		
44	Working Capital	24,419,769		192,548	(630,413)	
45	Weatherization Loans	2,304		-		
46	Misc Rate Base	-		-		
47						
48	Total Electric Plant:	12,823,937,828		192,548	1,129,487	
49						
50	Rate Base Deductions:					
51	Accum Prov For Deprec	(4,060,488,632)		-		
52	Accum Prov For Amort	(254,122,375)		-	(34,527)	
53	Accum Def Income Tax	(1,787,640,626)		(162,058)	(197,769)	
54	Unamortized ITC	(115,230)		-		
55	Customer Adv For Const	(31,278,618)		-		
56	Customer Service Deposits	-		-		
57	Misc Rate Base Deductions	(241,470,701)		6,309,806		
58						
59	Total Rate Base Deductions	(6,375,116,182)		6,147,748	(232,295)	
60						
61	Total Rate Base:	6,448,821,646		6,340,296	897,191	
62						
63	Return on Rate Base	6.982%		-0.334%	1.181%	
64						
65	Return on Equity	8.857%		-0.623%	2.200%	
66						
67	TAX CALCULATION:					
68	Operating Revenue	535,543,420		(28,038,382)	101,155,143	
69	Other Deductions					
70	Interest (AFUDC)	(32,072,175)		-		
71	Interest	140,487,434		141,261	19,989	
72	Schedule "M" Additions	506,676,468		-	63,742	
73	Schedule "M" Deductions	479,528,727		-	782,277	
74	Income Before Tax	454,275,902		(28,179,643)	100,416,619	
75						
76	State Income Taxes	20,624,126		(1,279,356)	4,558,914	
77	Taxable Income	433,651,776		(26,900,287)	95,857,704	
78						
79	Federal Income Taxes + Other	78,802,378		(5,649,060)	20,130,118	
	APPROXIMATE PRICE CHANGE	61,934,348		28,786,069	(101,578,361)	

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	Tab 7	Tab 8	Tab 10	UT Allocated
	Tax Adjustments	Rate Base Adjustments	Rebuttal Adjustments	Results of Operations December 2021
1 Operating Revenues:				[redacted]
2 General Business Revenues	-	-		
3 Interdepartmental	-	-		
4 Special Sales	-	-	(61,532)	
5 Other Operating Revenues	-	-	1,685,955	
6 Total Operating Revenues	-	-	1,624,423	
7				
8 Operating Expenses:				
9 Steam Production	-	(10,617,592)	2,591,195	
10 Nuclear Production	-	-		
11 Hydro Production	-	-	(144,391	
12 Other Power Supply	-	8,771,738	317,047	
13 Transmission	-	-	(2,128,947	
14 Distribution	-	-	503,836	
15 Customer Accounting	-	-	(571,359	
16 Customer Service & Info	-	-	(55,943	
17 Sales	-	-		
18 Administrative & General	-	-	1,327,489	
19				
20 Total O&M Expenses	-	(1,845,854)	1,838,928	
21				
22 Depreciation	-	50,838,862	(1,099,066	
23 Amortization	-	4,268,426	(2,958,845	
24 Taxes Other Than Income	14,331,400	-	4,203,647	
25 Income Taxes - Federal	(86,388,387)	(70,785,634)	6,696,442	
26 Income Taxes - State	(3,062,690)	(16,030,987)	381,796	
27 Income Taxes - Def Net	(4,677,906)	65,825,921	(1,879,644	
28 Investment Tax Credit Adj.	1,167,659	-		
29 Misc Revenue & Expense	-	681,136		
30				
31 Total Operating Expenses:	(78,629,924)	32,951,870	7,183,261	
32				
33 Operating Rev For Return:	78,629,924	(32,951,870)	(5,558,838	
34				
35 Rate Base:				
36 Electric Plant In Service	-	1,518,727,672	(60,667,479	
37 Plant Held for Future Use	-	(4,908,218)		
38 Misc Deferred Debits	-	(73,204,422)	(360,162	
39 Elec Plant Acq Adj	-	(4,810,804)	(1,708,124	
40 Nuclear Fuel	-	13,273,757	(34,785	
41 Prepayments	-	-	(26,595	
42 Fuel Stock	-	1,514,358		
43 Material & Supplies	-	(2,932,863)	4,521	
44 Working Capital	(837,303)	(1,214,406)	478,785	
45 Weatherization Loans	-	(2,305)		
46 Misc Rate Base	-	-		
47				
48 Total Electric Plant:	(837,303)	1,446,442,770	(62,313,840	
49				
50 Rate Base Deductions:				
51 Accum Prov For Deprec	-	83,718,740	(570,046	
52 Accum Prov For Amort	-	526,101	396,057	
53 Accum Def Income Tax	668,586,992	(59,478,549)	13,072,433	
54 Unamortized ITC	30,253	-		
55 Customer Adv For Const	-	(6,763,542)		
56 Customer Service Deposits	-	(16,275,584)		
57 Misc Rate Base Deductions	(574,605,644)	30,323,848	3,658,519	
58				
59 Total Rate Base Deductions	94,011,601	32,051,014	16,556,963	
60				
61 Total Rate Base:	93,174,298	1,478,493,784	(45,756,877	
62				
63 Return on Rate Base	1.131%	-2.110%	-0.032%	
64				
65 Return on Equity	2.107%	-3.931%	-0.059%	
66				
67 TAX CALCULATION:				
68 Operating Revenue	(14,331,400)	(53,942,570)	(360,244)	
69 Other Deductions				
70 Interest (AFUDC)	11,744,704	-	65,848	
71 Interest	2,075,916	32,940,723	(1,004,881	
72 Schedule "M" Additions	(57,404,777)	84,064,242	(5,016,935)	
73 Schedule "M" Deductions	(18,096,674)	350,286,385	(12,847,759	
74 Income Before Tax	(67,460,124)	(353,105,435)	8,409,613	
75				
76 State Income Taxes	(3,062,690)	(16,030,987)	381,796	
77 Taxable Income	(64,397,434)	(337,074,449)	8,027,817	
78				
79 Federal Income Taxes + Other	(86,388,387)	(70,785,634)	6,696,442	
APPROXIMATE PRICE CHANGE	(95,224,564)	195,693,205	(23,736,554	

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		Total Adjustments	Capital Cost - Cost of Debt	Capital Cost - Cost of Equity	O&M Escalation Removal	10.1 Wheeling Revenue Update	10.2 REC Revenues Update	10.3 NTUA Revenue Correction
1	Operating Revenues:						[redacted]	
2	General Business Revenues	-	-	-	-		[redacted]	-
3	Interdepartmental	-	-	-	-		[redacted]	-
4	Special Sales	(61,532)	-	-	-		[redacted]	77,250
5	Other Operating Revenues	1,685,955	-	-	-	(2,255,628	[redacted]	-
6	Total Operating Revenues	1,624,423	-	-	-	(2,255,628	[redacted]	77,250
7							[redacted]	
8	Operating Expenses:	-					[redacted]	
9	Steam Production	2,591,195	-	-	(1,444,665)		[redacted]	-
10	Nuclear Production	-	-	-	-		[redacted]	-
11	Hydro Production	(144,391)	-	-	24,796		[redacted]	-
12	Other Power Supply	317,047	-	-	(176,336)		[redacted]	-
13	Transmission	(2,128,947)	-	-	(198,296)		[redacted]	-
14	Distribution	503,836	-	-	(259,538)		[redacted]	-
15	Customer Accounting	(571,359)	-	-	(435,483)		[redacted]	-
16	Customer Service & Info	(55,943)	-	-	(48,197)		[redacted]	-
17	Sales	-	-	-	-		[redacted]	-
18	Administrative & General	1,327,489	-	-	(1,004,849)		[redacted]	-
19							[redacted]	
20	Total O&M Expenses	1,838,928	-	-	(3,542,567)		[redacted]	-
21							[redacted]	
22	Depreciation	(1,099,066)	-	-	-		[redacted]	-
23	Amortization	(2,958,845)	-	-	-		[redacted]	-
24	Taxes Other Than Income	4,203,647	-	-	-		[redacted]	-
25	Income Taxes - Federal	6,696,442	144,687	-	710,296	(452,149	[redacted]	15,485
26	Income Taxes - State	381,796	32,768	-	160,862	(102,399	[redacted]	3,507
27	Income Taxes - Def Net	(1,879,644)	-	-	-		[redacted]	-
28	Investment Tax Credit Adj.	-	-	-	-		[redacted]	-
29	Misc Revenue & Expense	4	-	-	-		[redacted]	-
30							[redacted]	
31	Total Operating Expenses:	7,183,261	177,454	-	(2,671,408)	(554,548	[redacted]	18,992
32							[redacted]	
33	Operating Rev For Return:	(5,558,838)	(177,454)	-	2,671,408	(1,701,079	[redacted]	58,258
34							[redacted]	
35	Rate Base:	-					[redacted]	
36	Electric Plant In Service	(60,667,479)	-	-	-		[redacted]	-
37	Plant Held for Future Use	-	-	-	-		[redacted]	-
38	Misc Deferred Debits	(360,162)	-	-	-		[redacted]	-
39	Elec Plant Acq Adj	(1,708,124)	-	-	-		[redacted]	-
40	Pensions	(34,785)	-	-	-		[redacted]	-
41	Prepayments	(26,595)	-	-	-		[redacted]	-
42	Fuel Stock	-	-	-	-		[redacted]	-
43	Material & Supplies	4,521	-	-	-		[redacted]	-
44	Working Capital	478,785	1,978	-	(29,776)	(6,181	[redacted]	212
45	Weatherization Loans	0	-	-	-		[redacted]	-
46	Misc Rate Base	-	-	-	-		[redacted]	-
47							[redacted]	
48	Total Electric Plant:	(62,313,840)	1,978	-	(29,776)	(6,181	[redacted]	212
49							[redacted]	
50	Rate Base Deductions:	-	-	-	-		[redacted]	-
51	Accum Prov For Deprec	(570,046)	-	-	-		[redacted]	-
52	Accum Prov For Amort	396,057	-	-	-		[redacted]	-
53	Accum Def Income Tax	13,072,433	-	-	105		[redacted]	-
54	Unamortized ITC	-	-	-	-		[redacted]	-
55	Customer Adv For Const	-	-	-	-		[redacted]	-
56	Customer Service Deposits	-	-	-	-		[redacted]	-
57	Misc Rate Base Deductions	3,658,519	-	-	-		[redacted]	-
58							[redacted]	
59	Total Rate Base Deductions	16,556,963	-	-	105		[redacted]	-
60							[redacted]	
61	Total Rate Base:	(45,756,877)	1,978	-	(29,671)	(6,181	[redacted]	212
62							[redacted]	
63	Return on Rate Base	-0.032%	-0.002%	0.000%	0.034%	-0.022%	[redacted]	0.001%
64							[redacted]	
65	Return on Equity	-0.059%	0.013%	0.000%	0.064%	-0.041%	[redacted]	0.001%
66							[redacted]	
67	TAX CALCULATION:						[redacted]	
68	Operating Revenue	(360,244)	-	-	3,542,567	(2,255,628	[redacted]	77,250
69	Other Deductions	-	-	-	-		[redacted]	-
70	Interest (AFUDC)	65,848	-	-	-		[redacted]	-
71	Interest	(1,004,881)	(721,751)	-	(658)	(137	[redacted]	5
72	Schedule "M" Additions	(5,016,935)	-	-	(0)		[redacted]	-
73	Schedule "M" Deductions	(12,847,759)	-	-	-		[redacted]	-
74	Income Before Tax	8,409,613	721,751	-	3,543,225	(2,255,491	[redacted]	77,245
75							[redacted]	
76	State Income Taxes	381,796	32,768	-	160,862	(102,399	[redacted]	3,507
77	Taxable Income	8,027,817	688,984	-	3,382,363	(2,153,091	[redacted]	73,738
78							[redacted]	
79	Federal Income Taxes + Other	6,696,442	144,687	-	710,296	(452,149	[redacted]	15,485
	APPROXIMATE PRICE CHANGE	(23,736,554)	(725,237)	(22,291,405)	(3,567,245)	2,266,267	[redacted]	(77,614)

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	10.11	10.12	10.13	10.14	10.15	10.16	10.17
	WEBA - UMWA Correction	WEBA - CY 2021 Annualization	Rebuttal Net Power Cost Alignment	Nodal Pricing Model Update	Other Decommissioning Cost – Colstrip - Correction	Electric Plant Acquisition Adjustment	Property Tax Update
1 Operating Revenues:					[redacted]		
2 General Business Revenues	-	-	-		[redacted]	-	-
3 Interdepartmental	-	-	-		[redacted]	-	-
4 Special Sales	-	-	(138,782)		[redacted]	-	-
5 Other Operating Revenues	-	-	-		[redacted]	-	-
6 Total Operating Revenues	-	-	(138,782)		[redacted]	-	-
7					[redacted]		
8 Operating Expenses:					[redacted]		
9 Steam Production	(176,643)	(175,007)	3,281,701		[redacted]	-	-
10 Nuclear Production	-	-	-		[redacted]	-	-
11 Hydro Production	(36,938)	(36,596)	-		[redacted]	-	-
12 Other Power Supply	(65,002)	(64,400)	571,144		[redacted]	-	-
13 Transmission	(52,167)	(51,684)	(639,365)		[redacted]	-	-
14 Distribution	(211,705)	(209,745)	-		[redacted]	-	-
15 Customer Accounting	(66,227)	(65,614)	-		[redacted]	-	-
16 Customer Service & Info	(14,311)	(14,179)	-		[redacted]	-	-
17 Sales	-	-	-		[redacted]	-	-
18 Administrative & General	(81,931)	(81,172)	-		[redacted]	-	-
19					[redacted]		
20 Total O&M Expenses	(704,924)	(698,396)	3,213,480		[redacted]	-	-
21					[redacted]		
22 Depreciation	-	-	-		[redacted]	-	-
23 Amortization	-	-	-	7,446	[redacted]	(2,070,614)	-
24 Taxes Other Than Income	-	-	-		[redacted]	-	4,407,030
25 Income Taxes - Federal	141,340	140,031	(672,133)	(19,114)	[redacted]	11,787	(883,624)
26 Income Taxes - State	32,010	31,713	(152,220)	(4,329)	[redacted]	2,669	(200,116)
27 Income Taxes - Def Net	-	-	-	20,635	[redacted]	503,955	-
28 Investment Tax Credit Adj.	-	-	-		[redacted]	-	-
29 Misc Revenue & Expense	-	-	-		[redacted]	-	-
30					[redacted]		
31 Total Operating Expenses:	(531,575)	(526,652)	2,389,128	4,653	[redacted]	(1,552,203)	3,323,289
32					[redacted]		
33 Operating Rev For Return:	531,575	526,652	(2,527,909)	(4,653)	[redacted]	1,552,203	(3,323,289)
34					[redacted]		
35 Rate Base:					[redacted]		
36 Electric Plant In Service	-	-	-	205,604	[redacted]	-	-
37 Plant Held for Future Use	-	-	-		[redacted]	-	-
38 Misc Deferred Debits	-	-	-		[redacted]	-	-
39 Elec Plant Acq Adj	-	-	-		[redacted]	(1,708,124)	-
40 Pensions	-	-	-		[redacted]	-	-
41 Prepayments	-	-	-		[redacted]	-	-
42 Fuel Stock	-	-	-		[redacted]	-	-
43 Material & Supplies	-	-	-		[redacted]	-	-
44 Working Capital	(5,925)	(5,870)	26,630	(260)	[redacted]	161	37,042
45 Weatherization Loans	-	-	-		[redacted]	-	-
46 Misc Rate Base	-	-	-		[redacted]	-	-
47					[redacted]		
48 Total Electric Plant:	(5,925)	(5,870)	26,630	205,364	[redacted]	(1,707,963)	37,042
49					[redacted]		
50 Rate Base Deductions:	-	-	-		[redacted]	-	-
51 Accum Prov For Deprec	-	-	-		[redacted]	-	-
52 Accum Prov For Amort	-	-	-	(4,047)	[redacted]	-	-
53 Accum Def Income Tax	-	-	-	(23,103)	[redacted]	-	-
54 Unamortized ITC	-	-	-		[redacted]	-	-
55 Customer Adv For Const	-	-	-		[redacted]	-	-
56 Customer Service Deposits	-	-	-		[redacted]	-	-
57 Misc Rate Base Deductions	-	-	-		[redacted]	-	-
58					[redacted]		
59 Total Rate Base Deductions	-	-	-	(27,160)	[redacted]	-	-
60					[redacted]		
61 Total Rate Base:	(5,925)	(5,870)	26,630	178,204	[redacted]	(1,707,963)	37,042
62					[redacted]		
63 Return on Rate Base	0.007%	0.007%	-0.032%	0.000%	[redacted]	0.021%	-0.043%
64					[redacted]		
65 Return on Equity	0.013%	0.013%	-0.060%	0.000%	[redacted]	0.040%	-0.080%
66					[redacted]		
67 TAX CALCULATION:					[redacted]		
68 Operating Revenue	704,924	698,396	(3,352,262)	(7,461)	[redacted]	2,070,614	(4,407,030)
69 Other Deductions	-	-	-		[redacted]	-	-
70 Interest (AFUDC)	-	-	-		[redacted]	-	-
71 Interest	(131)	(130)	591	3,954	[redacted]	(37,895)	822
72 Schedule "M" Additions	-	-	-	7,444	[redacted]	(2,049,712)	-
73 Schedule "M" Deductions	-	-	-	91,373	[redacted]	-	-
74 Income Before Tax	705,056	698,526	(3,352,853)	(95,348)	[redacted]	58,797	(4,407,852)
75					[redacted]		
76 State Income Taxes	32,010	31,713	(152,220)	(4,329)	[redacted]	2,669	(200,116)
77 Taxable Income	673,046	666,813	(3,200,633)	(91,019)	[redacted]	56,127	(4,207,735)
78					[redacted]		
79 Federal Income Taxes + Other	141,340	140,031	(672,133)	(19,114)	[redacted]	11,787	(883,624)
APPROXIMATE PRICE CHANGE	(708,975)	(702,409)	3,371,383	23,962	[redacted]	(2,238,716)	4,432,354

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	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED	REF#
Adjustment to Revenue:							
2019 True-Up for Kennecott Contract	456	1	24,012	UT	Situs	24,012	10.2.1
Pryor Mountain Projected 2021 REC Revenues	456	3	[redacted]	SG	43.997%	[redacted]	10.2.1

Description of Adjustment:

This incremental adjustment incorporates and accepts two changes to the total REC revenue amount as proposed by OCS. Specifically, these updates include an additional $24 thousand into the Test Year to account for the revised Kennecott REC Supply Agreement and the inclusion of the REC revenues associated with the Vitesse, LLC REC agreement.

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	Account	As Filed Total Company	Rebuttal Update Total Company	Adjustment	Ref
Adjustment to Revenue:					
Add December 2019 REC Revenues Reallocated According to RPS Eligibility:					
OR/CA/WA RPS Eligible:					
Reallocation of December 2019 Rev. for Non-RPS States	456	357,311	357,311	-	
Adjustment for CA RPS Banking	456	(14,288)	(14,288)	-	
Adjustment for OR RPS Banking	456	(260,664)	(260,664)	-	
Adjustment for WA RPS Banking	456	(82,359)	(82,359)	-	
		-	-	-	Adj. 3.2
OR/CA RPS Eligible					
Reallocation of December 2019 Rev. for Non-RPS States	456	1,476,746	1,476,746	-	
Adjustment for CA RPS Banking	456	(76,737)	(76,737)	-	
Adjustment for OR RPS Banking	456	(1,400,009)	(1,400,009)	-	
		-	-	-	Adj. 3.2
CA RPS Eligible					
Reallocation of December 2019 Rev. for Non-RPS States	456	3,623	3,623	-	
Adjustment for CA RPS Banking	456	(3,623)	(3,623)	-	
Adjustment for OR RPS - Ineligible Wind	456	(66,092)	(66,092)	-	
Adjustment for OR RPS - Ineligible Wind	456	66,092	66,092	-	
		-	-	-	Adj. 3.2
Remove REC Deferrals	456	1,132,426	1,132,426	-	Adj. 3.2
Retain 10 Percent Incentive on REC Revenue	456	(290,445)	(290,445)	-	Adj. 3.2
Kennecott Contract Situs Allocation	456	400,000	424,012	**24,012**	10.2.2
Kennecott Contract Administrative Fee	456	5,100	5,100	-	Adj. 3.2
Pryor Mountain Projected 2021 REC Revenues	456	-	[redacted]		10.2.2

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Utah General Rate Case December 2021
REC Revenue Update
Unadjusted Data
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Posting Date	Fin Accrual	Fin Reversal	Back Office Actual	SAP Total	Kennecott Removal	SAP Total w/o Kennecott
FERC Acct (Ref B1)	4562700	4562700	4562700		4562700	
SAP Acct	301944	301944	301945		301945	
January-19	(109)	32,948	(192,815)	(159,976)		(159,976)
February-19	(919,873)	109	-	(919,764)		(919,764)
March-19	(278,133)	919,873	(1,078,766)	(437,026)		(437,026)
April-19	(296,559)	278,133	(277,994)	(296,419)		(296,419)
May-19	(262,337)	296,559	(296,200)	(261,978)	50,000	(211,978)
June-19	(323,878)	262,337	(261,134)	(322,675)	50,000	(272,675)
July-19	(50,617)	323,878	(323,300)	(50,039)	50,000	(39)
August-19	(50,623)	50,617	(50,000)	(50,007)	50,000	(7)
September-19	(404,074)	50,623	(50,000)	(403,451)	50,000	(353,451)
October-19	(971,769)	404,074	(147,000)	(714,695)	50,000	(664,695)
November-19	(847,638)	971,769	(971,010)	(846,878)	50,000	(796,878)
December-19	(870,212)	847,638	(760,214)	(782,789)	50,000	(732,789)
12 ME December 2019 Total	(5,275,823)	4,438,559	(4,408,432)	(5,245,697)	400,000	**(4,845,697)**
						Ref 3.2.2

REC deferrals included in unadjusted results:

FERC Account	4562700	
Amount Yr. Ended December 2019	**1,132,426**	**Ref 3.2**

10 Percent Incentive Details:

	Utah Allocated	Ref
Total Utah-allocated Base Year REC Revenues (Excl. LJ indemnity loss)	2,904,446	Ref. 3.2.2
Less: 10 Percent Incentive to be retained by the Company	**290,445**	**Ref. 3.2.2**
Base Year REC Revenues (Excluding LJ indemnity loss)	2,614,002	

Situs Allocation:

Kennecott Contract
Annual Kennecott REC Revenue per Contract **600,000**

FERC Account 4562700
Kennecott Contract Amount Yr. Ended 2019 **400,000** **Ref 3.2**

Kennecott Base Revenue
Amount Yr. Ended 2019 **175,988** **Ref 3.2**

Kennecott Administrative Fee
Administrative Fee 2021 **5,100** **Ref 3.2**

SG Allocation:

Projected Revnues 2021
Pyror Mountain Revenue Amount 2021 [redacted]

CONFIDENTIAL – SUBJECT TO UTAH PUBLIC SERVICE COMMISSION RULES 746-1-602 AND 603

REDACTED

Rocky Mountain Power
Utah General Rate Case - December 2021
Escalation of Regular, Overtime, and Premium Labor
(Figures are in thousands)

Base Period: 12 Months Ended June 2019
Pro Forma: 12 Months Ending December 2021

CONFIDENTIAL
Pro Forma Increase to December 2021
Increases occur on the 26th of each month. For this exhibit, each increase is listed on the first day of the following month.

Group Code	Labor Group	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2	Officer/Exempt	[redacted]												
	12/26/2019													(1)
	12/26/2020													(1)
3	IBEW 125													
	1/26/2020													(1)
	1/26/2021													(1)
4	IBEW 659													
	4/26/2020													(1)
	4/26/2021													(3) CONF
5	UWUA 197													
	5/26/2020													(1)
	5/26/2021													(1)
8	UWUA 127													
	9/26/2020													(1)
	9/26/2021													(3) CONF
9	IBEW 57 WY													
	6/26/2020													(1,4)
	6/26/2021													(1)
11	IBEW 57 PD													
	1/26/2020													(1,4)
	1/26/2021													(1)
12	IBEW 57 PS													
	1/26/2020													(1,4)
	1/26/2021													(1)
13	PCCC Non-Exempt													
	12/26/2019													(1)
	12/26/2020													(2)
15	IBEW 57 CT													
	1/26/2020													(1,4)
	1/26/2021													(1)
16	IBEW 77													
	1/26/2020													(1)
	1/26/2021													(3) CONF
18	Non-Exempt													
	12/26/2019													(1)
	12/26/2020													(2)

(1) Labor increases supported by union contracts/actual increases.
(2) Projected labor increases supported by planned targets.
(3) Increase will be contingent on the future outcome of a new contract. (CONFIDENTIAL)
(4) One-time spot increase

CONFIDENTIAL – SUBJECT TO UTAH PUBLIC SERVICE COMMISSION RULES 746-1-602 AND 603

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Rocky Mountain Power
Utah General Rate Case - December 2021
Escalation of Regular, Overtime, and Premium Labor
(Figures are in thousands)

Base Period: 12 Months Ended June 2019
Pro Forma: 12 Months Ending December 2021

CONFIDENTIAL
Pro Forma Labor December 2021

Group Code	Labor Group	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Total
2	Officer/Exempt	[redacted]												
3	IBEW 125													
4	IBEW 659													
5	UWUA 197													
8	UWUA 127													
9	IBEW 57 WY													
11	IBEW 57 PD													
12	IBEW 57 PS													
13	PCCC Non-Exempt													
15	IBEW 57 CT													
16	IBEW 77													
18	Non-Exempt													
Grand Total														

Ref. 10.11.2

CONFIDENTIAL – SUBJECT TO UTAH PUBLIC SERVICE COMMISSION RULES 746-1-602 AND 603

REDACTED

Rocky Mountain Power
Utah General Rate Case - December 2021
WEBA – UMWA Correction
CONFIDENTIAL

Composite Labor Increases

			Ref.
Regular Time/Overtime/Premium Pay Annualize - Actual	**506,871,148**		10.11.2
Regular Time/Overtime/Premium Pay December 2021 - Pro Forma	**538,764,440**	CAGR[1]	10.11.2
% Increase	6.29%	2.47%	

Miscellaneous Bare Labor Escalation

Description	Account	December 2019 Actual	Pro Forma Increase	December 2021 Pro Forma	Pro Forma Adjustment	Ref.
Unused Sick Leave Accrual	5005XX	2,528,541	6.29%	2,687,641	**159,101**	10.11.2
Joint Owner Cutbacks	50109X	(1,201,493)	6.29%	(1,277,093)	**(75,600)**	10.11.2
		1,327,048		1,410,548	83,500	

Annual Incentive Plan Escalation

Description	Account	December 2019 Actual	December 2021 Pro Forma	Pro Forma Adjustment	Ref.
Annual Incentive Plan Compensation	[redacted]				

Test Year Annual Incentive Plan (AIP) Calculation

	Officer/Exempt Actual Wages	[2]PCCC Non-Exempt Actual Wages	Non-Exempt Actual Wages	Total Wages	Actual AIP	AIP as a % of Wages
Cy 2017 [redacted]	[redacted]					
3-year Total	560,493,576			579,741,755	84,691,432	14.61%
Test Year	[redacted]			[redacted]	[redacted]	[redacted]
	Ref 10.11.5				**Ref 10.11.2**	

[1]Compound Annual Growth Rate
[2] Effective CY 2018, Non-exempt are not eligible for AIP.

CONFIDENTIAL – SUBJECT TO UTAH PUBLIC
SERVICE COMMISSION RULES 746-1-602 AND 603

REDACTED

Rocky Mountain Power
Utah General Rate Case - December 2021
Escalation of Regular, Overtime, and Premium Labor
(Figures are in thousands)

Base Period: 12 Months Ended June 2019
Pro Forma: 12 Months Ending December 2021

CONFIDENTIAL

Pro Forma Increase to December 2021

Increases occur on the 26th of each month. For this exhibit, each increase is listed on the first day of the following month.

Group Code	Labor Group	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2	Officer/Exempt	[redacted]												
	12/26/2019													(1)
	12/26/2020													(1)
3	IBEW 125													
	1/26/2020													(1)
	1/26/2021													(1)
4	IBEW 659													
	4/26/2020													(1)
	4/26/2021													(3) CONF
5	UWUA 197													
	5/26/2020													(1)
	5/26/2021													(1)
8	UWUA 127													
	9/26/2020													(1)
	9/26/2021													(3) CONF
9	IBEW 57 WY													
	6/26/2020													(1,4)
	6/26/2021													(1)
11	IBEW 57 PD													
	1/26/2020													(1,4)
	1/26/2021													(1)
12	IBEW 57 PS													
	1/26/2020													(1,4)
	1/26/2021													(1)
13	PCCC Non-Exempt													
	12/26/2019													(1)
	12/26/2020													(2)
15	IBEW 57 CT													
	1/26/2020													(1,4)
	1/26/2021													(1)
16	IBEW 77													
	1/26/2020													(1)
	1/26/2021													(3) CONF
18	Non-Exempt													
	12/26/2019													(1)
	12/26/2020													(2)

(1) Labor increases supported by union contracts/actual increases.
(2) Projected labor increases supported by planned targets.
(3) Increase will be contingent on the future outcome of a new contract. (CONFIDENTIAL)
(4) A one-time spot increase

CONFIDENTIAL – SUBJECT TO UTAH PUBLIC SERVICE COMMISSION RULES 746-1-602 AND 603

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Rocky Mountain Power
Utah General Rate Case - December 2021
Escalation of Regular, Overtime, and Premium Labor
(Figures are in thousands)

Base Period: 12 Months Ended June 2019
Pro Forma: 12 Months Ending December 2021

CONFIDENTIAL
Pro Forma Labor December 2021

Group Code	Labor Group
2	Officer/Exempt
3	IBEW 125
4	IBEW 659
5	UWUA 197
8	UWUA 127
9	IBEW 57 WY
11	IBEW 57 PD
12	IBEW 57 PS
13	PCCC Non-Exempt
15	IBEW 57 CT
16	IBEW 77
18	Non-Exempt
Grand Total	

[redacted]

Ref. 10.12.2

REDACTED

Rocky Mountain Power
Utah General Rate Case - December 2021
WEBA – CY 2021 Annualization
CONFIDENTIAL

Composite Labor Increases

			Ref.
Regular Time/Overtime/Premium Pay Annualize - Actual	**506,871,148**		10.12.2
Regular Time/Overtime/Premium Pay December 2021 - Pro Forma	**536,719,169**	CAGR[1]	10.12.2
% Increase	5.89%	2.32%	

Miscellaneous Bare Labor Escalation

Description	Account	December 2019 Actual	Pro Forma Increase	December 2021 Pro Forma	Pro Forma Adjustment	Ref.
Unused Sick Leave Accrual	5005XX	2,528,541	5.89%	2,677,438	**148,898**	10.12.2
Joint Owner Cutbacks	50109X	(1,201,493)	5.89%	(1,272,245)	**(70,752)**	10.12.2
		1,327,048		1,405,193	78,146	

Annual Incentive Plan Escalation

Description	December 2019	December 2021	Pro Forma
Annual Incentive Plan Compensation	[redacted]		

Test Year Annual Incentive Plan (AIP) Calculation

	Officer/Exempt Actual Wages	[2]PCCC Non-Exempt Actual Wages	Non-Exempt Actual Wages	Total Wages	Actual AIP	AIP as a % of Wages
Cy 2017	[redacted]					
Cy 2018						
Cy 2019						
3-year Total	560,493,576			579,741,755	84,691,432	14.61%
Test Year	[redacted]			[redacted]	[redacted]	[redacted]
	Ref 10.12.5				Ref 10.12.2	

[1]Compound Annual Growth Rate
[2] Effective CY 2018, Non-exempt are not eligible for AIP.

Rocky Mountain Power
Utah General Rate Case - December 2021
Other Decommissioning Cost – Colstrip - Correction
CONFIDENTIAL

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	UTAH ALLOCATED	REF#
Adjustment to Expense							
Annual Incremental Decomm. Costs	407	3	[redacted]	SG	43.997%	[redacted]	10.15.1
Adjustment to Rate Base							
Accum. Reg Liab. - Incr. Decomm.	254	3		SG	43.997%		10.15.1
Adjustment to Tax:							
Schedule M Adjustment	SCHMAT	3		SG	43.997%		10.15.1
Deferred Income Tax Expense	41110	3		SG	43.997%		10.15.1
Accumulated Def Inc Tax Balance	190	3		SG	43.997%		10.15.1

Description of Adjustment:

This adjustment corrects the remaining life calculation for the Colstrip plant to the appropriate seven years.

Rocky Mountain Power
Utah General Rate Case - December 2021
Other Decommissioning Cost - Colstrip - Correction
CONFIDENTIAL

REDACTED

	Account	As Filed Total Company	Rebuttal Update Total Company	Adjustment	REF#
Adjustment to Expense		[redacted]			
Annual Incremental Decomm. Costs	407				10.15.2
Adjustment to Rate Base					
Accum. Reg Liab. - Incr. Decomm.	254				10.15.2
Adjustment to Tax:					
Schedule M Adjustment	SCHMAT				10.15.2
Deferred Income Tax Expense	41110				10.15.2
Accumulated Def Inc Tax Balance	190				10.15.2

CONFIDENTIAL – SUBJECT TO UTAH PUBLIC SERVICE COMMISSION RULES 746-1-602 AND 603

REDACTED

Rocky Mountain Power
Utah General Rate Case - December 2021
Other Decommissioning Cost - Colstrip - Correction
2018 Depreciation Study
CONFIDENTIAL

Plant	Plant Closure Date	Remaining Life (Years)	Incremental Decommissioning Costs	Total Company Annual Amount
Hunter	2042	22.00	[redacted]	
Huntington	2036	16.00		
Dave Johnston	2027	7.00		
Jim Bridger	2037	17.00		
Naughton	2029	9.00		
Wyodak	2039	19.00		
Hayden	2030	10.00		
Colstrip	2027	7.00		
			Total	
				Ref 10.15.1

	407 Mthly Accum.	SCHMAT Tax	41110 Def Inc Tax Exp	254 Reg. Liab.	190 ADIT
Dec-20	[redacted]				
Jan-21					
Feb-21					
Mar-21					
Apr-21					
May-21					
Jun-21					
Jul-21					
Aug-21					
Sep-21					
Oct-21					
Nov-21					
Dec-21					
Annual Total	[redacted]				
		Ref 10.15.1	Ref 10.15.1		
			13 Mo. Avg.	[redacted]	
				Ref 10.15.1	Ref 10.15.1

Rocky Mountain Power
Utah General Rate Case - December 2021
Pro Forma Plant Data Update
CONFIDENTIAL

REDACTED

Project Description	Notes	FERC Account	Factor	In-Service	Jan 2020 - Dec 2021 Plant Additions	December 2021 13 Month Avg
Steam Production						
Hunter 303 CCR Forced Oxidation Project	UAE 3.9	312	SG	Jun-21	(13,322,397)	(7,173,599)
Naughton U1 OH Turbine Major (HP/IP/LP) CY21	UAE 3.9	312	SG	Dec-21	(3,496,635)	(268,972)
Wyodak U1 - Boiler Waterwall Replacement CY20/CY21	UAE 3.9	312	SG	May-21	(3,041,969)	(1,871,981)
Craig CRGU5 RELIABILITY/ABILITY TO SERVE CY20	UAE 3.9	312	SG	Dec-20	(1,907,860)	(1,907,860)
Craig CRGU0 NEW COAL STORAGE SILOS CY21	UAE 3.9	312	SG	Dec-21	(1,870,321)	(143,871)
Jim Bridger U2 Burners Major 21	UAE 3.9	312	SG	Jun-21	(1,786,957)	(962,208)
Craig CRGU5 REGULATORY ENVIRON & SAFETY CY20	UAE 3.9	312	SG	Dec-20	(1,483,898)	(1,483,898)
Wyodak U1 - Ovation Major Upgrade CY21	UAE 3.9	312	SG	May-21	(1,480,209)	(910,898)
Colstrip COLU5 CCR-CONSTRUCt DRY WASTE DISPOSAL CY21 TUCK	UAE 3.9	312	SG	Dec-21	(1,164,537)	(89,580)
Wyodak U1 - Pulverizer Overhaul "A" CY21	UAE 3.9	312	SG	Apr-21	(1,147,696)	(794,559)
Wyodak U1 - Scrubber 'A' Chamber Reinforcement CY19/CY20	UAE 3.9	312	SG	May-21	(1,017,139)	(625,932)
Wyodak U1 - Pulverizer Overhaul "C" CY21	UAE 3.9 New Capital Additions	312	SG	Dec-21	1,129,014	173,694
Wyodak U1 - Pulverizer Overhaul "D" CY21	UAE 3.9 New Capital Additions	312	SG	Oct-20	1,131,914	1,131,914
Naughton U2 OH Mechanical Dust Collectors CY20	UAE 3.9 New Capital Additions	312	SG	May-21	1,373,272	845,090
Naughton U2 OH Boiler: Header Replacement CY20	UAE 3.9 New Capital Additions	312	SG	May-21	1,441,992	887,380
Steam Production Total					**(26,643,427)**	**(13,195,278)**
Hydro Production Plant						
Soda Spinning Reserve	UAE 3.9	332	SG-U	Sep-21	(4,611,888)	(1,419,043)
Swift 1 Spillway Gate Bulkhead	UAE 3.9	332	SG-P	Jun-21	(4,374,266)	(2,355,374)
Toketee Dam Rehabilitation Evaluation	UAE 3.9	332	SG-P	Dec-21	(3,524,437)	(271,111)
Swift 1 Spillway Gate Retrofit	UAE 3.9	332	SG-P	Oct-21	(3,030,460)	(699,337)
Swift 1 Minimum Discharge Line	UAE 3.9	332	SG-P	Nov-20	(2,286,463)	(2,286,463)
Bull Trout Yale Downstream Facility	UAE 3.9	332	SG-P	Nov-21	(1,706,528)	(262,543)
Yale Spillway Gate Improvements	UAE 3.9	332	SG-P	Dec-21	(1,566,440)	(120,495)
ILR 4.4.1 Swift FSC NTS Upgrade Phase 2	UAE 3.9	332	SG-P	Dec-21	(1,370,909)	(105,455)
Eastside Flowline Removal	UAE 3.9	332	SG-P	Nov-20	(1,122,005)	(1,122,005)
ILR 4.4.1 Swift FSC Attract Pump DM Mod	UAE 3.9	332	SG-P	Dec-21	(1,085,303)	(83,485)
Yale Saddle Dam Seismic Remediation	UAE 3.9 New Capital Additions	332	SG-P	Nov-21	1,739,624	267,634
					(22,939,075)	**(8,457,675)**
Other Production						
Lakeside Blk 1 U12 Generator Rotor Replacement	UAE 3.9	343	SG	Apr-20	(2,095,411)	(2,095,411)
Hermiston U1 - OH - Stator/Generator rewind	UAE 3.9 New Capital Additions	343	SG	Dec-20	1,048,229	1,048,229
Currant Creek U3 ST Diaphragm Replacement	UAE 3.9 New Capital Additions	343	SG	Apr-20	1,115,512	1,115,512
Cedar Springs Wind Project 200 MW 2020	Remove as Filed	343	SG-W	Dec-20	[redacted]	[redacted]
Cedar Springs Wind Project 200 MW 2020	Remove as Filed	343	SG-W	Dec-20	[redacted]	[redacted]
Ekola Flats Wind Project 250 MW 2020	Remove as Filed	343	SG-W	Dec-20	[redacted]	[redacted]
TB Flats Wind Project 500 MW 2020	Remove as Filed	343	SG-W	Dec-20	[redacted]	[redacted]
Pryor Mtn Wind Project 240 MW 2020	Remove as Filed	343	SG-W	Dec-20	[redacted]	[redacted]
Cedar Springs Wind Project 200 MW 2020	Update Project Data	343	SG-W	Nov-20	[redacted]	[redacted]
Ekola Flats Wind Project 250 MW 2020	Update Project Data	343	SG-W	Various	[redacted]	[redacted]
TB Flats Wind Project 500 MW 2020	Update Project Data	343	SG-W	Various	[redacted]	[redacted]
Pryor Mtn Wind Project 240 MW 2020	Update Project Data	343	SG-W	Various	[redacted]	[redacted]
Other Production Total					**(320,529,085)**	**(320,358,703)**
Tranmsission						
TMP Transmission Major Projects - PP (Flint New 115kV to 12.5kV Substation)	UAE 3.9	355	SG	Various	(13,280,307)	(8,952,833)
TMP Trans Main Grid West (Shevlin Park Substation Increase Capacity)	UAE 3.9	355	SG	Various	(6,297,100)	(2,045,950)
Blue Creek - Bothwell Tap 46 kV Reconductor/Rebuild	UAE 3.9 New Capital Additions	355	SG	May-21	1,986,400	1,222,400
Southeast - Install New Control Building	UAE 3.9 New Capital Additions	355	SG	Dec-21	1,017,500	78,269
Spare 230-161kV 150 MVA Xfmr	UAE 3.9 New Capital Additions	355	SG	Sep-21	1,000,000	307,692
UDOT I-15 NB; Bangerter Hwy to I-215	UAE 3.9 New Capital Additions	355	SG	Oct-20	2,256,384	2,256,384
Tyson Foods, 8 MW	UAE 3.9 New Capital Additions	355	SG	Dec-20	1,473,800	1,473,800
El Monte Substation Expansion	UAE 3.9 New Capital Additions	355	SG	Mar-20	2,642,587	2,642,587
Wildfire Mitigation - Trans	Remove as Filed	355	SG	Various	(41,679,625)	(29,766,265)
Wildfire Mitigation - Trans	Update Project Data	355	SG	Various	35,689,188	22,659,323
Pavant Transformer Protection	Remove as Filed	355	SG	Dec-20	(1,819,906)	(1,819,906)
Jordanelle - Midway Construct 138 kV Line	Remove as Filed	355	SG	Nov-20	(18,287,278)	(18,287,278)
Reroute JB Goshen 345kV line	Remove as Filed	355	SG	Oct-20	(1,959,432)	(1,959,432)
Parowan Valley Reg Replacement	Remove as Filed	355	SG	Dec-20	(969,907)	(969,907)
Block 216 Tower Service Request	Remove as Filed	355	SG	Oct-20	(822,662)	(822,662)
Pavant Transformer Protection	Update Project Data	355	SG	Dec-20	1,312,413	1,312,413
Jordanelle - Midway Construct 138 kV Line	Update Project Data	355	SG	Nov-21	25,213,948	3,879,069
Reroute JB Goshen 345kV line	Update Project Data	355	SG	Oct-21	3,437,559	793,283
Total Transmission					**(9,086,438)**	**(27,999,013)**

Rocky Mountain Power
Utah General Rate Case - December 2021
Pro Forma Plant Data Update
CONFIDENTIAL

REDACTED

Project Description	Notes	FERC Account	Factor	In-Service	Jan 2021 - Dec 2021 Depreciation Expense
Steam Production					
Hunter 303 CCR Forced Oxidation Project	UAE 3.9	403SP	SG	Jun-21	(384,242)
Naughton U1 OH Turbine Major (HP/IP/LP) CY21	UAE 3.9	403SP	SG	Dec-21	(7,758)
Wyodak U1 - Boiler Waterwall Replacement CY20/CY21	UAE 3.9	403SP	SG	May-21	(101,234)
Craig CRGU5 RELIABILITY/ABILITY TO SERVE CY20	UAE 3.9	403SP	SG	Dec-20	(101,587)
Craig CRGU0 NEW COAL STORAGE SILOS CY21	UAE 3.9	403SP	SG	Dec-21	(4,149)
Jim Bridger U2 Burners Major 21	UAE 3.9	403SP	SG	Jun-21	(51,539)
Craig CRGU5 REGULATORY ENVIRON & SAFETY CY20	UAE 3.9	403SP	SG	Dec-20	(79,012)
Wyodak U1 - Ovation Major Upgrade CY21	UAE 3.9	403SP	SG	May-21	(49,260)
Colstrip COLU5 CCR-CONSTRUCt DRY WASTE DISPOSAL CY21 TUCK	UAE 3.9	403SP	SG	Dec-21	(2,584)
Wyodak U1 - Pulverizer Overhaul "A" CY21	UAE 3.9	403SP	SG	Apr-21	(43,287)
Wyodak U1 - Scrubber 'A' Chamber Reinforcement CY19/CY20	UAE 3.9	403SP	SG	May-21	(33,849)
Wyodak U1 - Pulverizer Overhaul "C" CY21	UAE 3.9 New Capital Additions	403SP	SG	Dec-21	7,514
Wyodak U1 - Pulverizer Overhaul "D" CY21	UAE 3.9 New Capital Additions	403SP	SG	Oct-20	60,270
Naughton U2 OH Mechanical Dust Collectors CY20	UAE 3.9 New Capital Additions	403SP	SG	May-21	45,701
Naughton U2 OH Boiler: Header Replacement CY20	UAE 3.9 New Capital Additions	403SP	SG	May-21	47,988
Steam Production Total					**(697,027)**
Hydro Production Plant					
Soda Spinning Reserve	UAE 3.9	403HP	SG-U	Sep-21	(63,321)
Swift 1 Spillway Gate Bulkhead	UAE 3.9	403HP	SG-P	Jun-21	(65,507)
Toketee Dam Rehabilitation Evaluation	UAE 3.9	403HP	SG-P	Dec-21	(4,060)
Swift 1 Spillway Gate Retrofit	UAE 3.9	403HP	SG-P	Oct-21	(17,455)
Swift 1 Minimum Discharge Line	UAE 3.9	403HP	SG-P	Nov-20	(63,214)
Bull Trout Yale Downstream Facility	UAE 3.9	403HP	SG-P	Nov-21	(5,898)
Yale Spillway Gate Improvements	UAE 3.9	403HP	SG-P	Dec-21	(1,804)
ILR 4.4.1 Swift FSC NTS Upgrade Phase 2	UAE 3.9	403HP	SG-P	Dec-21	(1,579)
Eastside Flowline Removal	UAE 3.9	403HP	SG-P	Nov-20	(31,020)
ILR 4.4.1 Swift FSC Attract Pump DM Mod	UAE 3.9	403HP	SG-P	Dec-21	(1,250)
Yale Saddle Dam Seismic Remediation	UAE 3.9 New Capital Additions	403HP	SG-P	Nov-21	6,012
					(249,096)
Other Production					
Lakeside Blk 1 U12 Generator Rotor Replacement	UAE 3.9	403OP	SG	Apr-20	(73,461)
Hermiston U1 - OH - Stator/Generator rewind	UAE 3.9 New Capital Additions	403OP	SG	Dec-20	36,749
Currant Creek U3 ST Diaphragm Replacement	UAE 3.9 New Capital Additions	403OP	SG	Apr-20	39,108
Cedar Springs Wind Project 200 MW 2020	Remove as Filed	403OP	SG-W	Dec-20	[redacted]
Cedar Springs Wind Project 200 MW 2020	Remove as Filed	403OP	SG-W	Dec-20	[redacted]
Ekola Flats Wind Project 250 MW 2020	Remove as Filed	403OP	SG-W	Dec-20	[redacted]
TB Flats Wind Project 500 MW 2020	Remove as Filed	403OP	SG-W	Dec-20	[redacted]
Pryor Mtn Wind Project 240 MW 2020	Remove as Filed	403OP	SG-W	Dec-20	[redacted]
Cedar Springs Wind Project 200 MW 2020	Update Project Data	403OP	SG-W	Nov-20	[redacted]
Ekola Flats Wind Project 250 MW 2020	Update Project Data	403OP	SG-W	Various	[redacted]
TB Flats Wind Project 500 MW 2020	Update Project Data	403OP	SG-W	Various	[redacted]
Pryor Mtn Wind Project 240 MW 2020	Update Project Data	403OP	SG-W	Various	[redacted]
Other Production Total					**(15,503,327)**
Tranmsission					
TMP Transmission Major Projects - PP (Flint New 115kV to 12.5kV Substation)	UAE 3.9	403TP	SG	Various	(151,089)
TMP Trans Main Grid West (Shevlin Park Substation Increase Capacity)	UAE 3.9	403TP	SG	Various	(32,385)
Blue Creek - Bothwell Tap 46 kV Reconductor/Rebuild	UAE 3.9 New Capital Additions	403TP	SG	May-21	21,346
Southeast - Install New Control Building	UAE 3.9 New Capital Additions	403TP	SG	Dec-21	729
Spare 230-161kV 150 MVA Xfmr	UAE 3.9 New Capital Additions	403TP	SG	Sep-21	5,015
UDOT I-15 NB; Bangerter Hwy to I-215	UAE 3.9 New Capital Additions	403TP	SG	Oct-20	38,795
Tyson Foods, 8 MW	UAE 3.9 New Capital Additions	403TP	SG	Dec-20	25,340
El Monte Substation Expansion	UAE 3.9 New Capital Additions	403TP	SG	Mar-20	45,436
Wildfire Mitigation - Trans	Remove as Filed	403TP	SG	Various	(512,615)
Wildfire Mitigation - Trans	Update Project Data	403TP	SG	Various	390,497
Pavant Transformer Protection	Remove as Filed	403TP	SG	Dec-20	(31,291)
Jordanelle - Midway Construct 138 kV Line	Remove as Filed	403TP	SG	Nov-20	(314,424)
Reroute JB Goshen 345kV line	Remove as Filed	403TP	SG	Oct-20	(33,690)
Parowan Valley Reg Replacement	Remove as Filed	403TP	SG	Dec-20	(16,676)
Block 216 Tower Service Request	Remove as Filed	403TP	SG	Oct-20	(14,144)
Pavant Transformer Protection	Update Project Data	403TP	SG	Dec-20	22,565
Jordanelle - Midway Construct 138 kV Line	Update Project Data	403TP	SG	Nov-21	54,190
Reroute JB Goshen 345kV line	Update Project Data	403TP	SG	Oct-21	12,313
Total Transmission					**(490,089)**

CONFIDENTIAL – SUBJECT TO UTAH PUBLIC SERVICE COMMISSION RULES 746-1-602 AND 603

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Rocky Mountain Power
Utah General Rate Case - December 2021
Pro Forma Plant Data Update
CONFIDENTIAL

Project Description	Notes	FERC Account	Factor	In-Service	Dec 21 Accum Depr Reserve	December 2021 13 Month Avg
Steam Production						
Hunter 303 CCR Forced Oxidation Project	UAE 3.9	108SP	SG	Jun-21	384,242	111,407
Naughton U1 OH Turbine Major (HP/IP/LP) CY21	UAE 3.9	108SP	SG	Dec-21	7,758	597
Wyodak U1 - Boiler Waterwall Replacement CY20/CY21	UAE 3.9	108SP	SG	May-21	101,234	33,225
Craig CRGU5 RELIABILITY/ABILITY TO SERVE CY20	UAE 3.9	108SP	SG	Dec-20	104,519	53,726
Craig CRGU0 NEW COAL STORAGE SILOS CY21	UAE 3.9	108SP	SG	Dec-21	4,149	319
Jim Bridger U2 Burners Major 21	UAE 3.9	108SP	SG	Jun-21	51,539	14,943
Craig CRGU5 REGULATORY ENVIRON & SAFETY CY20	UAE 3.9	108SP	SG	Dec-20	81,293	41,787
Wyodak U1 - Ovation Major Upgrade CY21	UAE 3.9	108SP	SG	May-21	49,260	16,167
Colstrip COLU5 CCR-CONSTRUCt DRY WASTE DISPOSAL CY21 TUCK	UAE 3.9	108SP	SG	Dec-21	2,584	199
Wyodak U1 - Pulverizer Overhaul "A" CY21	UAE 3.9	108SP	SG	Apr-21	43,287	15,865
Wyodak U1 - Scrubber 'A' Chamber Reinforcement CY19/CY20	UAE 3.9	108SP	SG	May-21	33,849	11,110
Wyodak U1 - Pulverizer Overhaul "C" CY21	UAE 3.9 New Capital Additions	108SP	SG	Dec-21	(7,514)	(771)
Wyodak U1 - Pulverizer Overhaul "D" CY21	UAE 3.9 New Capital Additions	108SP	SG	Oct-20	(68,968)	(38,833)
Naughton U2 OH Mechanical Dust Collectors CY20	UAE 3.9 New Capital Additions	108SP	SG	May-21	(45,701)	(14,999)
Naughton U2 OH Boiler: Header Replacement CY20	UAE 3.9 New Capital Additions	108SP	SG	May-21	(47,988)	(15,750)
Steam Production Total					**693,541**	**228,992**
Hydro Production Plant						
Soda Spinning Reserve	UAE 3.9	108HP	SG-U	Sep-21	63,321	11,133
Swift 1 Spillway Gate Bulkhead	UAE 3.9	108HP	SG-P	Jun-21	65,507	18,993
Toketee Dam Rehabilitation Evaluation	UAE 3.9	108HP	SG-P	Dec-21	4,060	312
Swift 1 Spillway Gate Retrofit	UAE 3.9	108HP	SG-P	Oct-21	17,455	2,417
Swift 1 Minimum Discharge Line	UAE 3.9	108HP	SG-P	Nov-20	70,614	39,007
Bull Trout Yale Downstream Facility	UAE 3.9	108HP	SG-P	Nov-21	5,898	605
Yale Spillway Gate Improvements	UAE 3.9	108HP	SG-P	Dec-21	1,804	139
ILR 4.4.1 Swift FSC NTS Upgrade Phase 2	UAE 3.9	108HP	SG-P	Dec-21	1,579	121
Eastside Flowline Removal	UAE 3.9	108HP	SG-P	Nov-20	34,652	19,141
ILR 4.4.1 Swift FSC Attract Pump DM Mod	UAE 3.9	108HP	SG-P	Dec-21	1,250	96
Yale Saddle Dam Seismic Remediation	UAE 3.9 New Capital Additions	108HP	SG-P	Nov-21	(6,012)	(617)
					260,128	**91,349**
Other Production						
Lakeside Blk 1 U12 Generator Rotor Replacement	UAE 3.9	108OP	SG	Apr-20	117,199	80,469
Hermiston U1 - OH - Stator/Generator rewind	UAE 3.9 New Capital Additions	108OP	SG	Dec-20	(38,036)	(19,661)
Currant Creek U3 ST Diaphragm Replacement	UAE 3.9 New Capital Additions	108OP	SG	Apr-20	(62,392)	(42,838)
Cedar Springs Wind Project 200 MW 2020	Remove as Filed	108OP	SG-W	Dec-20	[redacted]	[redacted]
Cedar Springs Wind Project 200 MW 2020	Remove as Filed	108OP	SG-W	Dec-20	[redacted]	[redacted]
Ekola Flats Wind Project 250 MW 2020	Remove as Filed	108OP	SG-W	Dec-20	[redacted]	[redacted]
TB Flats Wind Project 500 MW 2020	Remove as Filed	108OP	SG-W	Dec-20	[redacted]	[redacted]
Pryor Mtn Wind Project 240 MW 2020	Remove as Filed	108OP	SG-W	Dec-20	[redacted]	[redacted]
Cedar Springs Wind Project 200 MW 2020	Update Project Data	108OP	SG-W	Nov-20	[redacted]	[redacted]
Ekola Flats Wind Project 250 MW 2020	Update Project Data	108OP	SG-W	Various	[redacted]	[redacted]
TB Flats Wind Project 500 MW 2020	Update Project Data	108OP	SG-W	Various	[redacted]	[redacted]
Pryor Mtn Wind Project 240 MW 2020	Update Project Data	108OP	SG-W	Various	[redacted]	[redacted]
Other Production Total					**13,247,387**	**5,493,529**
Tranmsission						
TMP Transmission Major Projects - PP (Flint New 115kV to 12.5kV Substation)	UAE 3.9	108TP	SG	Various	157,355	80,389
TMP Trans Main Grid West (Shevlin Park Substation Increase Capacity)	UAE 3.9	108TP	SG	Various	33,619	16,030
Blue Creek - Bothwell Tap 46 kV Reconductor/Rebuild	UAE 3.9 New Capital Additions	108TP	SG	May-21	(21,346)	(7,006)
Southeast - Install New Control Building	UAE 3.9 New Capital Additions	108TP	SG	Dec-21	(729)	(56)
Spare 230-161kV 150 MVA Xfmr	UAE 3.9 New Capital Additions	108TP	SG	Sep-21	(5,015)	(882)
UDOT I-15 NB; Bangerter Hwy to I-215	UAE 3.9 New Capital Additions	108TP	SG	Oct-20	(47,022)	(27,625)
Tyson Foods, 8 MW	UAE 3.9 New Capital Additions	108TP	SG	Dec-20	(26,415)	(13,745)
El Monte Substation Expansion	UAE 3.9 New Capital Additions	108TP	SG	Mar-20	(82,048)	(59,331)
Wildfire Mitigation - Trans	Remove as Filed	108TP	SG	Various	618,561	325,995
Wildfire Mitigation - Trans	Update Project Data	108TP	SG	Various	(422,917)	(188,042)
Pavant Transformer Protection	Remove as Filed	108TP	SG	Dec-20	32,618	16,972
Jordanelle - Midway Construct 138 kV Line	Remove as Filed	108TP	SG	Nov-20	354,429	197,218
Reroute JB Goshen 345kV line	Remove as Filed	108TP	SG	Oct-20	40,834	23,989
Parowan Valley Reg Replacement	Remove as Filed	108TP	SG	Dec-20	17,383	9,045
Block 216 Tower Service Request	Remove as Filed	108TP	SG	Oct-20	17,032	9,960
Pavant Transformer Protection	Update Project Data	108TP	SG	Dec-20	(23,522)	(12,240)
Jordanelle - Midway Construct 138 kV Line	Update Project Data	108TP	SG	Nov-21	(54,190)	(5,558)
Reroute JB Goshen 345kV line	Update Project Data	108TP	SG	Oct-21	(12,313)	(1,705)
Total Transmission					**576,315**	**363,411**

Rocky Mountain Power
Utah General Rate Case - December 2021
Pryor Mountain and TB Flats – Phase 2
CONFIDENTIAL

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Project	Date	Project Capital Amount	
Incremental New Wind Cap Adds		[redacted]	
Pryor Mtn Wind Project 240 MW 2020	Jun-2021		
TB Flats Wind Project 500 MW 2020	Jun-2021		
		357,704,000	**Ref 10.22.1**
Incremental O&M		**2021 O&M**	
Pryor Mtn Wind Project 240 MW 2020		[redacted]	
TB Flats Wind Project 500 MW 2020			
		2,535,501	**Ref 10.22**

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Rocky Mountain Power
Exhibit RMP___(SRM-4R)
Docket No. 20-035-04
Witness: Steven R. McDougal

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Exhibit Accompanying Rebuttal Testimony of Steven R. McDougal

2021 Property Tax Estimation

October 2020

THIS ATTACHMENT IS CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER

Rocky Mountain Power
Exhibit RMP___(SRM-5R)
Docket No. 20-035-04
Witness: Steven R. McDougal

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Steven R. McDougal

TCJA Regulatory Liability Balances

October 2020

Rocky Mountain Power
Utah General Rate Case
TCJA Regulatory Liability Balances

Reconciliation of Utah Deferred Tax Reform Balances

Item	Non-EDIT Tax Benefits	Protected EDIT	Non-Protected EDIT: Property	Non-Protected EDIT: Non-Property	Non-Protected EDIT: Def. Amort.	Non-Protected EDIT: Subtotal	Total
Utah EDIT @ 01/01/2018: 17-035-69	**(199,127,901)**	**(615,974,874)**	**(104,732,415)**	**(22,560,698)**	**0**	**(127,293,113)**	**(942,395,888)**
Classification Correction	0	17,996,367	(17,996,367)	0	0	**(17,996,367)**	**0**
Utah EDIT @ 01/01/2018: FINAL	**(199,127,901)**	**(597,978,507)**	**(122,728,782)**	**(22,560,698)**	**0**	**(145,289,480)**	**(942,395,888)**
Deferred Amort. of Protected EDIT: 2018	0	26,227,482	0	0	(26,227,482)	**(26,227,482)**	**0**
Deferred Amort. of Protected EDIT: 2019	0	26,403,073	0	0	(26,403,073)	**(26,403,073)**	**0**
Deferred Amort. of Protected EDIT: 2020	0	36,883,008	0	0	(36,883,008)	**(36,883,008)**	**0**
Utah EDIT @ 12/31/2020, Before Gross-Up	**(199,127,901)**	**(508,464,944)**	**(122,728,782)**	**(22,560,698)**	**(89,513,563)**	**(234,803,043)**	**(942,395,888)**
Gross-Up Factor	1.000000	1.326024	1.326024	1.326024	1.326024	1.326024	
Utah EDIT @ 12/31/2020, Before Amounts Used	**(199,127,901)**	**(674,236,719)**	**(162,741,310)**	**(29,916,027)**	**(118,697,133)**	**(311,354,470)**	**(1,184,719,090)**
Less: TCJA Rate Reduction	183,000,000	0	0	0	0	**0**	**183,000,000**
Less: Plant Buy-Downs - 2018	4,890,414	0	138,877,696	29,916,027	0	**168,793,723**	**173,684,137**
Less: Plant Buy-Downs - 2019	4,890,414	0	0	0	0	**0**	**4,890,414**
Less: Plant Buy-Downs - 2020	4,890,414	0	0	0	0	**0**	**4,890,414**
Utah EDIT @ 12/31/2020, Before Proposed Use	**(1,456,659)**	**(674,236,719)**	**(23,863,614)**	**0**	**(118,697,133)**	**(142,560,747)**	**(818,254,125)**
Less: Dave Johnston Buy-Down	0	0	23,863,614	0	0	**23,863,614**	**23,863,614**
Less: 2017 Protocol Regulatory Asset	1,456,659	0	0	0	11,743,341	**11,743,341**	**13,200,000**
Less: EIM Benefit Regulatory Asset	0	0	0	0	9,573,636	**9,573,636**	**9,573,636**
Less: Carbon Regulatory Asset	0	0	0	0	10,292,396	**10,292,396**	**10,292,396**
Less: Deer Creek Regulatory Asset	0	0	0	0	21,679,262	**21,679,262**	**21,679,262**
Less: Electric Plant Acquisition Adj. Craig and Hayden	0	0	0	0	2,743,431	**2,743,431**	**2,743,431**
Less: Proposed Amortization - $38.2m 2021, $26.8m 2022[1]	0	0	0	0	62,665,067	**62,665,067**	**62,665,067**
Utah EDIT @ 12/31/2020	**0**	**(674,236,719)**	**0**	**0**	**(0)**	**(0)**	**(674,236,719)**

TCJA Non-EDIT Tax Benefits

Item	2018	2019	2020	Total
Current Tax Benefit	(65,890,404)	(65,890,404)	(65,890,404)	**(197,671,212)**
Accrued Interest	(527,997)	(345,430)	(583,262)	**(1,456,689)**
Total Non-EDIT Tax Benefits	**(66,418,401)**	**(66,235,834)**	**(66,473,666)**	**(199,127,901)**

Use of TCJA Tax Benefits

Item	2018	2019	2020	Total
TCJA Rate Reduction - Schedule 197	61,000,000	61,000,000	61,000,000	183,000,000
Plant Buy-Down: Current Tax	4,890,414	4,890,414	4,890,414	14,671,242
Plant Buy-Down: Non-protected EDIT	168,793,723	0	0	168,793,723
Total Amounts Used	**234,684,137**	**65,890,414**	**65,890,414**	**366,464,965**

Comparison of Protected EDIT Amortization: RSGM v ARAM

Item	RSGM	ARAM	Difference
Protected EDIT Amortization 12/31/2018	(26,227,482)	(13,628,800)	(12,598,682)
Protected EDIT Amortization 12/31/2019	(26,403,073)	(12,505,625)	(13,897,448)
Protected EDIT Amortization 12/31/2020	(36,883,008)	(12,329,759)	(24,553,249)
Total	**(89,513,563)**	**(38,464,184)**	**(51,049,379)**

Footnotes:
(1) Includes interest.

Rocky Mountain Power
Utah General Rate Case
Schedule 197
$ - Thousands

Carrying Charge Rate[1]
3.88%

	Period	Beginning Balance	Refund	Carrying Charge	Ending Balance
1	Jan-21	$ 62,665	$ (2,242)	$ 199	$ 60,622
2	Feb-21	60,622	(2,242)	192	58,572
3	Mar-21	58,572	(2,242)	186	56,516
4	Apr-21	56,516	(2,242)	179	54,452
5	May-21	54,452	(2,242)	172	52,383
6	Jun-21	52,383	(2,242)	166	50,306
7	Jul-21	50,306	(4,120)	156	46,342
8	Aug-21	46,342	(4,120)	143	42,365
9	Sep-21	42,365	(4,120)	130	38,374
10	Oct-21	38,374	(4,120)	117	34,371
11	Nov-21	34,371	(4,120)	104	30,356
12	Dec-21	30,356	(4,120)	91	26,327
	Total		**$ (38,176)**	**$ 1,837**	**$ 26,327**
13	Jan-22	$ 26,327	$ (2,237)	$ 82	$ 24,171
14	Feb-22	24,171	(2,237)	75	22,009
15	Mar-22	22,009	(2,237)	68	19,840
16	Apr-22	19,840	(2,237)	61	17,664
17	May-22	17,664	(2,237)	53	15,481
18	Jun-22	15,481	(2,237)	46	13,291
19	Jul-22	13,291	(2,237)	39	11,093
20	Aug-22	11,093	(2,237)	32	8,889
21	Sep-22	8,889	(2,237)	25	6,678
22	Oct-22	6,678	(2,237)	18	4,459
23	Nov-22	4,459	(2,237)	11	2,233
24	Dec-22	2,233	(2,237)	4	0
	Total		**$ (26,840)**	**$ 513**	**$ 0**

(1) Carrying Charge rate beginning April 1, 2020 was approved at 3.88% per Docket No. 20-035-T01.

Rocky Mountain Power
Exhibit RMP___(SRM-6R)
Docket No. 20-035-04
Witness: Steven R. McDougal

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Steven R. McDougal

EBA Base – Allocated

October 2020

Rocky Mountain Power
Utah General Rate Case
EBA Base Detail
Twelve Months Ending December 2021

Line	Category	Cost Item	FERC Account	Allocation Factor	Total Company	Utah Allocated	Reference
	Net Power Cost						
1		Sales for Resale	447	SG	$ 223,178,425	$ 98,192,924	Final GRID Study
2		Sales for Resale	447	SE	-	-	Final GRID Study
3		Fuel Expense	501	S	-	-	Final GRID Study
4		Fuel Expense	501	SE	607,284,852	263,295,693	Final GRID Study
5		Fuel Expense	503	SE	4,497,520	1,949,954	Final GRID Study
6		Fuel Expense	547	SE	294,479,761	127,675,262	Final GRID Study
7		Purchased Power	555	SE	50,516,280	21,901,944	Final GRID Study
8		Purchased Power	555	SG	550,174,501	242,063,016	Final GRID Study
9		Wheeling Expense	565	SG	40,073,217	17,631,213	Final GRID Study
10		Wheeling Expense	565	SE	106,677,607	46,251,367	Final GRID Study
11		**Total Net Power Costs:**			**$ 1,430,525,312**	**$ 622,575,525**	
12							
13	Utah Situs Purchased Power Adjustments		555	S	**1,570,674**	**1,570,674**	Final GRID Study
14		**Total Net Power Costs:**			**$ 1,432,095,986**	**$ 624,146,199**	Exhibit RMP__(SRM-2R), Page 2.1
15							
16	Revenues from Transmission of Electricity by Others						
17		Other Electric Revenue	456.1	SG	$ 100,733,354	$ 44,320,155	Exhibit RMP__(SRM-3), Tab B-1, Exhibit RMP__(SRM_2R), Page 10.1
18		Other Electric Revenue	456.1	SE	14,558,486	6,312,008	Exhibit RMP__(SRM-3), Tab B-1
19		**Total Revenues from Transmission of Electricity by Others:**			**$ 115,291,840**	**$ 50,632,163**	
20							
21	Production Tax Credits						
22		Production Tax Credits	40910	SG	$ (182,078,210)	$ (80,109,857)	Exhibit RMP__(SRM-2R), Page 2.18
23		Tax Bump Up			(59,361,919)	(26,117,759)	
24		**Total Production Tax Credits:**			**$ (241,440,129)**	**$ (106,227,616)**	
25							
26		**Total ECAM Base:**			**$ 1,075,364,017**	**$ 467,286,420**	
27							
28							
29		Federal/State Combined Tax Rate			24.5866%		Exhibit RMP__(SRM-2R), Page 2.0
30		Tax Bump up factor = (1/(1-tax rate))			1.3260		

Rocky Mountain Power
Exhibit RMP___(SRM-7R)
Docket No. 20-035-04
Witness: Steven R. McDougal

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Steven R. McDougal

Wildland Fire Base

October 2020

Rocky Mountain Power
Utah General Rate Case - December 2021
Wildland Fire Mitigation Balancing Account

Utah Wildland Fire Mitigation Balancing Account - Base Calculation Mechanism

	2021	
Revenue	Total	UT Allocated[1]
Revenue Requirement	**11,382,340**	**9,586,112**
Expenses[5]		
Total Distribution O&M[2]	4,403,127	4,403,127
Total Transmission O&M[2]	558,496	245,724
Total Depreciation Expense[3]	1,421,437	1,090,060
Total Taxes[4]	63,513	63,513
Total Expenses	**6,446,572**	**5,802,424**
Rate Base		
EPIS	54,461,863	41,772,075
Less Accum Depreciation	(777,551)	(618,461)
Total Rate Base	**53,684,313**	**41,153,615**
Pre-tax Return on Rate Base	**9.19%**	**9.19%**

Footnotes:
1- 2021 UT GRC allocation factors, SG allocation UT: 43.997%.
2- Operating and Maintenance expense as reflected in Exhibit RMP__(SRM-2R)
3- 2021 Composite Dist. and Trans. Depr. rates are 2.541% and 1.719%, respectively.
4- Property taxes were assumed at 1.20% as reflected in Exhibit RMP__(SRM-4R) and assumed on Jan. 1, 2021 gross plant bala
5- Expenses have been updated to the House Bill 0066 Plan.

Rocky Mountain Power
Exhibit RMP___(SRM-8R)
Docket No. 20-035-04
Witness: Steven R. McDougal

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Steven R. McDougal

Accelerated Wind Schedule

October 2020

Rocky Mountain Power
Utah General Rate Case - December 2021
Estimated Accelerated Wind Schedule

Plant Site	Gross Plant	Accum Deprec	Net Book	UT DPU Proposal 10 Years	UT DPU Proposal Depreciation	Assumed 30 Year Depreciation	Depreciation Difference	SG Factor	UT Allocated Depreciation Expense
Leaning Juniper	107,427,452.30	(44,363,614.04)	63,063,838.26	10	6,306,384	2,102,128	4,204,256	43.997%	1,849,767
Seven Mile Hill 1	134,087,865.25	(47,216,937.39)	86,870,927.86	10	8,687,093	2,895,698	5,791,395	43.997%	2,548,069
Seven Mile Hill 2	27,771,736.13	(9,687,388.05)	18,084,348.08	10	1,808,435	602,812	1,205,623	43.997%	530,444
Glenrock 1	118,121,160.87	(44,368,169.08)	73,752,991.79	10	7,375,299	2,458,433	4,916,866	43.997%	2,163,298
Rolling Hills	90,084,349.94	(31,800,315.73)	58,284,034.21	10	5,828,403	1,942,801	3,885,602	43.997%	1,709,568
Glenrock 3	41,873,923.60	(14,908,575.15)	26,965,348.45	10	2,696,535	898,845	1,797,690	43.997%	790,939
McFadden	37,875,458.51	(13,267,451.05)	24,608,007.46	10	2,460,801	820,267	1,640,534	43.997%	721,794
High Plains	148,024,831.02	(51,610,289.01)	96,414,542.01	10	9,641,454	3,213,818	6,427,636	43.997%	2,827,999
Goodnoe Hills	136,744,923.18	(50,400,384.56)	86,344,538.62	10	8,634,454	2,878,151	5,756,303	43.997%	2,532,629
Marengo I	169,820,479.35	(72,035,431.74)	97,785,047.61	10	9,778,505	3,259,502	6,519,003	43.997%	2,868,198
Marengo II	87,430,631.81	(35,575,921.74)	51,854,710.07	10	5,185,471	1,728,490	3,456,981	43.997%	1,520,985
Dunlap	154,623,589.78	(53,654,442.54)	100,969,147.24	10	10,096,915	3,365,638	6,731,276	43.997%	2,961,593
Foote Creek	38,822,821.39	(28,234,029.98)	10,588,791.41	10	1,058,879	352,960	705,919	43.997%	310,587
	1,292,709,223.13		795,586,273.07		79,558,627	26,519,542	**53,039,085**		**23,335,870**

Rocky Mountain Power
Docket No. 20-035-04
Witness: Kyle T. Moore

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Rebuttal Testimony of Kyle T. Moore

October 2020

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Rocky Mountain Power ("Rocky Mountain Power" or the "Company").

A. My name is Kyle T. Moore and my business address is 1407 West North Temple, Suite 330, Salt Lake City, Utah 84116. I am a power market originator and have maintained this position with the Company since the year 2015.

I. QUALIFICATIONS AND PURPOSE

Q. Please describe your education and business experience.

A. I have a B.A. in Finance and an M.B.A. from the University of Utah. In my current role as power market originator, I am responsible for negotiating qualifying facility contracts, negotiating interruptible retail special contracts, managing wholesale or market-based energy and capacity contracts with other utilities and power marketers, and negotiating contracts for and facilitating renewable energy procurement on behalf of customers seeking service under the Company's renewable energy tariffs. Prior to my current role I worked at the Company from 2007 through 2015 in various finance, planning, and structure and pricing roles. I also worked in the regulatory department at Kern River Gas Transmission Company for approximately three years and as an energy consultant at Energy Strategies in Salt Lake City for approximately five years.

Q. Please state the purpose of your testimony.

A. First, I adopt the direct testimony of Mr. William J. Comeau. Second, I offer rebuttal testimony responsive to the Division of Public Utilities ("Division") witness Mr. Robert A. Davis, Office of Consumer Services ("OCS") witnesses Ms. Alyson Anderson and Ms. Donna Ramas, and Utah Clean Energy witness Ms. Sarah Wright (collectively, the "Intervenor Witnesses").

Q. Please state your qualifications to adopt Mr. Comeau's testimony.

A. I am very familiar with the Company's current Subscriber Solar Program under Electric Service Schedule No. 73 ("Schedule 73"), previously approved in Docket No. 15-035-61. I have this familiarity because I was involved in designing Schedule 73, administered the Request for Proposals ("RFP") through which the resource was procured, and my work has been integral to the continuation of the program. I was also involved in the design revisions to Schedule 73, as set forth in Mr. Comeau's testimony.

II. SUMMARY

Q. Please summarize the Intervenor Witnesses' testimony.

A. Division witness Mr. Davis testified that the proposed Subscriber Solar Program is reasonable and generally supports it.[1] Mr. Davis nonetheless expresses concerns regarding interaction between the legacy and proposed Subscription Solar Program, customer migration and mitigation of that migration, energy balancing account ("EBA") impacts, and subscription ramp rate.[2] Mr. Davis further suggests various reporting requirements, and, after the review of information provided, the Division reserved the right to make further recommendations.[3]

OCS witnesses Ms. Anderson and Ms. Ramas oppose the program on three grounds, summarized as follows: (1) accounting concerns; (2) alleged lack of detail; and (3) Subscriber Solar Program cost recovery.[4]

[1] Direct Testimony of Robert A. Davis at lines 85-91.
[2] *Id.* at lines 206-209.
[3] *Id.* at lines 215-238.
[4] Direct Testimony of Alyson Anderson at lines 102-115.

UCE witness Ms. Wright supports expansion of the Subscriber Solar Program, while also raising concerns regarding Subscriber Solar Program cost recovery and suggesting a carve-out for low-income customers.

Q. How do you respond?

A. My testimony is organized as follows:

- First, I provide additional support for the Company's reasoning to expand the Subscriber Solar Program.
- Second, I respond to concerns raised by the Intervenor Witnesses regarding the operational overlap between the current Schedule 73 and proposed changes thereto, including blending the programs and mitigating customer migration.
- Third, I address concerns raised by the Intervenor Witnesses regarding impacts of the Subscriber Solar Program on the EBA and subscription ramp rate.
- Finally, I respond to the request from Mr. Davis to provide detailed reporting on the Subscriber Solar Program, offer a solution to Ms. Ramas' accounting concerns, and address Ms. Wright's proposal on low-income customer involvement.

III. SUBSCRIBER SOLAR PROGRAM EXPANSION

Q. Please provide additional detail regarding the requested updates to the Subscriber Solar Program.

A. As noted on page 4 of Mr. Comeau's direct testimony, the Company is responding to strong customer interest for the Subscriber Solar Program.

Q. Please expand on Mr. Comeau's testimony.

A. Two examples are worth noting regarding the strong interest the Company has witnessed for the Subscriber Solar Program. First, when the Company opened up the availability for the Full Coverage Option in July 2020, it had 307 subscribers request to change over to the Full Coverage Option almost immediately. And these requests were not generated through any marketing, other than advising subscribers that the Full Coverage Option was available. In fact, 169 of those 307 subscribers requested the change before the Full Coverage Option was available. Second, the Company currently has 5,134,557 annual kilowatt-hours ("kWh") on its waiting list from large customers for a new resource.

Q. Why is this data important?

A. Because it underscores the existing demand for expansion of the Subscriber Solar Program before any steps are taken to procure a new solar resource, including the marketing of that new resource. In other words, assuming the Subscriber Solar Program expansion is approved as proposed, the Company already has over 10 percent of the contemplated next resource subscribed by large customers. I will address concerns regarding the ramp rate for the remaining 90 percent in my testimony below.

IV. SUBSCRIBER SOLAR PROGRAM OVERLAP

Q. Have solar costs declined since inception of the Subscriber Solar Program?

A. Yes, which Mr. Davis notes in his testimony, but this shouldn't result in significant customer program migration as Mr. Davis implies.[5] This is true, as Mr. Davis later

[5] Direct Testimony of Robert A. Davis at lines 114-116.

notes, because the new billing methodology is nearly identical in results.[6]

Q. Does the Company have a plan for mitigating the impacts of migration, should migration become an issue?

A. Yes. The Company has set up the rate design for the Subscriber Solar Program expansion such that there should be relative cost parity across the two programs. As shown in the Exhibit RMP___(KTM-1R), Subscriber Solar Expansion – Cost Model, both the cost of the proposed expansion resource and the current program resource, Pavant III Solar, result in substantially similar rates under the proposed rate structure, approximately 1.2 cents per kWh. This rate is also substantially similar to the cost of the current program, as pointed out by Mr. Davis. Should the Company acquire a resource with an anticipated renewable adder substantially lower than the currently expected value, the Company will seek, through a Commission filing, to average the rates across to the two pricing methodologies to maintain pricing parity between the programs and thus mitigate the impacts of migration.

Additionally, to help manage program migration, the Company proposes to update the proposed tariff language to note the rates/changes to the Solar Delivery Charge should remain in effect for a period of time beyond January 1, 2021, to account for departures and new customers before the new resource is online. The Company also plans to implement additional measures to further manage program migration. For example, six months before the expansion resource goes into operation, the Company proposes to stop accepting new entrants to the original program and transition to the new pricing. Also, assuming the Subscriber Solar expansion is approved, if, prior to the expansion project going into operation, a

[6] *Id.* at line 166-167.

customer wants to sign up for subscription amounts that exceed the amount then available, then the Company would inform the customer that it may sign up for future subscriptions under the anticipated expansion project.

V. SUBSCRIBER SOLAR PROGRAM COST RECOVERY

Q. Has the Company been successful in its efforts to ensure the Subscriber Solar Program did not burden non-participants with the costs of the program?

A. Yes. As conceded by OCS witness Alyson Anderson, the costs associated with the Subscriber Solar Program that flow through the EBA to non-participants and included in the test year are "negligible."[7] Table 1 below details the historical Subscriber Solar EBA costs as a percentage of overall EBA costs and underscores this point.

Table 1: Subscriber Solar EBA Costs

	Subscriber Solar Generation	Subscriber Solar Sold**	Subscriber Solar Un-Sold	EBA Impact, $ millions	% of EBA
2017*	48,146,997	43,417,636	4,729,361	$257,691	0.036%
2018	50,511,859	47,704,730	2,807,129	$148,216	0.021%
2019	48,133,302	47,749,442	383,860	$20,268	0.003%

**January 2017 was not sold due to billing implementation, generation was 1,360,547 January 2017*
***The program is managed to sell 48,000,000 kWh per year based on the size and annual forecast of the resource*

Q. Is it reasonable to assess a negligible amount of costs associated with the Subscriber Solar Program to non-subscribers?

A. Yes. The risk and cost is small as shown from the experience with the current program and as shown later in my testimony for the proposed expansion program. However, the Company believes that offering customers this option to support

[7] Direct Testimony of Alyson Anderson at line 80.

renewable energy through more cost-effective large-scale resources rather than potentially from behind the meter generation is beneficial for all customers because these participants will continue to contribute to fixed cost recovery, which helps maintain lower rates for all customers. The Company views the subscriber solar program as another viable option for customers, similar to the Company's programs for customer generators, which also have some potential risk and cost to other customers.

To address concerns regarding how well the Company is marketing the program to support full subscription in order to mitigate any potential costs to non-participants in the EBA, parties can evaluate through the EBA each year whether, through the Company's actions (or inactions), the cost has reached an unjustifiably large amount and should be disallowed in rates.

Q. What is the Company's plan to address concerns regarding ramp rate for subscriptions to the proposed new solar resource?

A. A communications and marketing plan will be used, similar to what was put together for the legacy Subscriber Solar program. The new resource will be marketed under the Blue Sky program umbrella so that it is easily recognizable as a renewable program option. The Company will create broad, easy-to-understand, awareness to reach customers directly at events, through targeted communications, online advertising, and statement communications.

Communications and marketing around the new resource will commence soon after the Company gets approval for the new rate design and obtains a power purchase agreement for a resource. The Company will create a waiting list for customers expressing early interest and will contact those customers directly when the program is approved. Given the Company's success with filling subscriptions for the existing Subscriber Solar Program, it has a high degree of confidence that this strategy will be successful.

Q. If the ramp rate takes longer than the Company currently anticipates, how much of an impact will that have on the EBA and non-participating customers?

A. Based on the performance of the original program it is the Company's reasonable expectation that the resource will be fully subscribed by the time the facility reaches its commercial operation date. However, if the ramp rate to full subscription takes longer than anticipated the potential dollar impact of the program can be determined by multiplying the expected renewable adder revenue by the reduction in program participation megawatt hours purchased. Below, Table 2 provides various examples of reduced subscription rates and the impact that reduction has in terms of overall impact to EBA costs:

Table 2: Potential Impact of Reduced Subscriptions

Subscription Rate	Potential Annual Adder Impact	EBA, 2019 Total UT NPC $ before wheeling revenue	% of EBA
50%	$288,029	$716,029,809	0.040%
75%	$144,014	$716,029,809	0.020%
90%	$57,606	$716,029,809	0.008%

<u>Table 2 Assumptions</u>

Anticipated	*100%*	
Total Anticipated MWh	*48,000*	
Anticipated Renewable	*$12.00*	*$/MWh*

VI. REPORTING REQUIREMENTS AND STAKEHOLDER ENGAGEMENT

Q. How does the Company respond to Mr. Davis' reporting requests?

A. The Company will continue its reporting obligations and is willing to address any additional stated concerns of the Division, including the naming of the two programs so customers can easily distinguish between them.

Q. How does the Company respond to concerns raised by Ms. Ramas regarding various accounting issues?

A. The Company has two responses. First, concerns from Ms. Ramas relate to the current structure of the Solar Subscriber Program, to which she is not recommending any changes.[8] Second, the Company commits to hold a stakeholder meeting in order to provide the Company the opportunity to present and explain amortization expense associated with the "liability account," which would allow for real-time questions and answers.

Q. How does the Company respond to Ms. Wright's request for a low-income carve-out for the Subscriber Solar Program?

A. The Company does not support a low-income carve-out because the Subscriber Solar program operates as a premium on customers' bills for an optional service. Creating a low-income carve-out for this optional service would necessarily increase the premium paid by program participants to subsidize the carve-out, which could further implicate the migration and subscription concerns raised by other parties. Furthermore, as Ms. Wright notes, the Company's recent 2019 IRP already identifies solar resources to be a significant part of the Company's least-cost, least-risk portfolio. The Company believes that continuing to provide customers low-cost energy, which will include a growing level of renewable energy when it is cost-effectively feasible, will better serve low-income customers than a premium program offering.

[8] Direct Testimony of Donna Ramas at lines 1668-1673.

However, if the Commission is interested in a low-income subscriber solar carve-out, it is important to consider that the current program is not structured to account for such a carve-out so any consideration of this proposal would be better addressed in the context of potential future expansions.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Rocky Mountain Power
Exhibit RMP___(KTM-1R)
Docket No. 20-035-04
Witness: Kyle T. Moore

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Kyle T. Moore

Subscriber Solar Expansion – Cost Model

October 2020

Project Size & Production

		NPV	Total	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Calendar Year				2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Pavant III Solar Size (MW)	20			20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Pavant III Solar Size (MWh)	27.4%	457,083	768,028	48,002	48,002	48,002	48,002	48,002	48,002	48,002	48,002	48,002	48,002	48,002	48,002	48,002	48,002	48,002	48,002

Renewable Adder

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
PPA Prices																	
Pavant III Solar	$/MWH	$52.80	$52.80	$52.80	$52.80	$52.80	$52.80	$52.80	$52.80	$52.80	$52.80	$52.80	$52.80	$52.80	$52.80	$52.80	$52.80
Avoided Costs/IRP Model Valuation																	
Pavant III Solar	$/MWH	$46.78	$46.78	$46.78	$46.78	$46.78	$46.78	$46.78	$46.78	$46.78	$46.78	$46.78	$46.78	$46.78	$46.78	$46.78	$46.78
Renewable Adder																	
Pavant III Solar	$/MWH	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02	$6.02

Expenses

(Thousands of Dollars)

	On-Going	NPV	Total	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Calendar Year				2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Program Costs				PROPOSED RE-ALLOCATION															
Administration/Interest	150		2,974	185	185	161	164	168	171	176	180	183	188	192	197	201	204	209	213
Marketing	75		1,552	125	125	80	82	84	86	88	90	92	94	96	98	101	102	104	107
Billing	-		200	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Program Costs		**$2,844**	**$4,726**	**$410**	**$410**	**$241**	**$245**	**$252**	**$257**	**$263**	**$270**	**$275**	**$281**	**$288**	**$295**	**$302**	**$306**	**$313**	**$320**
Expense Increase (Decrease)		**$2,844**		**410**	**410**	**241**	**245**	**252**	**257**	**263**	**270**	**275**	**281**	**288**	**295**	**302**	**306**	**313**	**320**
Levelized		**$2,844**		**299**	**299**	**299**	**299**	**299**	**299**	**299**	**299**	**299**	**299**	**299**	**299**	**299**	**299**	**299**	**299**

Total Cost Adder

(Thousands of Dollars)

	NPV	Total	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Total Costs (Adder + Program Costs)	**$5,595**	**$9,402**	**588**	**588**	**588**	**588**	**588**	**588**	**588**	**588**	**588**	**588**	**588**	**588**	**588**	**588**	**588**	**588**
		$/MWh	$12.2	$12.2	$12.2	$12.2	$12.2	$12.2	$12.2	$12.2	$12.2	$12.2	$12.2	$12.2	$12.2	$12.2	$12.2	$12.2
		¢ per kWh	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22
		Inflation Forecast	1.90%	2.00%	2.50%	2.50%	2.40%	2.30%	2.30%	2.30%	2.30%	2.30%	2.20%	2.20%	2.20%	2.10%	2.10%	2.10%
		Cumulative Inflation	102.00%	104.00%	107.00%	109.00%	112.00%	114.00%	117.00%	120.00%	122.00%	125.00%	128.00%	131.00%	134.00%	136.00%	139.00%	142.00%

Project Size & Production																						
					1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Calendar Year				Total	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Project 2 Size (MW)	20				-	-	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Project 2 Size (MWh)	27.4%	449,351			-	-	48,002	48,002	48,002	48,002	48,002	48,002	48,002	48,002	48,002	48,002	48,002	48,002	48,002	48,002	48,002	48,002
Renewable Adder																						
PPA Prices																						
Project 2			$/MWH		$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00
Avoided Costs/IRP Model Valuation																						
Project 2 - (Placeholder Solar Avoided Cost)			$/MWH		$23.00	$23.00	$23.00	$23.00	$23.00	$23.00	$23.00	$23.00	$23.00	$23.00	$23.00	$23.00	$23.00	$23.00	$23.00	$23.00	$23.00	$23.00
Renewable Adder																						
Project 2			$/MWH		$7.00	$7.00	$7.00	$7.00	$7.00	$7.00	$7.00	$7.00	$7.00	$7.00	$7.00	$7.00	$7.00	$7.00	$7.00	$7.00	$7.00	$7.00
Expenses					(Thousands of Dollars)																	
					1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Calendar Year				Total	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Program Costs		On-Going			PROPOSED EXPANSION COSTS																	
Administration		75		2,098	65	78	80	82	84	86	88	90	92	94	96	98	101	102	104	107	109	109
Marketing		75		2,555	300	300	80	82	84	86	88	90	92	94	96	98	101	102	104	107	109	109
Billing		-		250	250	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Program Costs		**$2,666**		**$4,902**	**$615**	**$378**	**$161**	**$164**	**$168**	**$171**	**$176**	**$180**	**$183**	**$188**	**$192**	**$197**	**$201**	**$204**	**$209**	**$213**	**$218**	**$218**
Expense Increase (Decrease)		**$2,666**			**615**	**378**	**161**	**164**	**168**	**171**	**176**	**180**	**183**	**188**	**192**	**197**	**201**	**204**	**209**	**213**	**218**	**218**
Levelized		**$2,334**			**0**	**0**	**249**	**249**	**249**	**249**	**249**	**249**	**249**	**249**	**249**	**249**	**249**	**249**	**249**	**249**	**249**	**249**
Total Cost Adder					(Thousands of Dollars)																	
		NPV		Total	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Total Costs (Adder + Program Costs)		**$5,479**		**$11,706**	**0**	**0**	**585**	**585**	**585**	**585**	**585**	**585**	**585**	**585**	**585**	**585**	**585**	**585**	**585**	**585**	**585**	**585**
				$/MWh	0	$0.0	$12.2	$12.2	$12.2	$12.2	$12.2	$12.2	$12.2	$12.2	$12.2	$12.2	$12.2	$12.2	$12.2	$12.2	$12.2	$12.2
				¢ per kWh	0.00	0.00	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22
				Inflation Forecast	1.90%	2.00%	2.50%	2.50%	2.40%	2.30%	2.30%	2.30%	2.30%	2.30%	2.20%	2.20%	2.20%	2.10%	2.10%	2.10%	2.10%	2.10%
				Cumulative Inflation	102.00%	104.00%	107.00%	109.00%	112.00%	114.00%	117.00%	120.00%	122.00%	125.00%	128.00%	131.00%	134.00%	136.00%	139.00%	142.00%	145.00%	145.00%

REDACTED
Rocky Mountain Power
Docket No. 20-035-04
Witness: Julie Lewis

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Direct Testimony of Julie Lewis

October 2020

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Rocky Mountain Power ("PacifiCorp" or the "Company").

A. My name is Julie Lewis. My business address is 825 NE Multnomah Street, Suite 1800, Portland, Oregon 97232. I am currently the Vice President of People for PacifiCorp.

Q. Please describe your education and professional experience.

A. I joined PacifiCorp in 1980 and have worked in human resources since 1985. During this time, I have taken on roles of increasing responsibility, including as Director of Compensation and Benefits for two years, before assuming my current role in 2018.

I. PURPOSE & SUMMARY

Q. What is the purpose of your rebuttal testimony in this case?

A. The purpose of my rebuttal testimony is to explain why the Public Service Commission of Utah ("Commission") should reject certain wage and labor related adjustments proposed by Utah Association of Energy Users ("UAE") witness Mr. Kevin Higgins.

Q. Please summarize your testimony.

A. In my testimony I explain why employee incentive payments should not be disallowed. The Company's incentive program is not a "bonus," is structured to provide benefits to customers consistent with Commission precedent, and is part of the Company's total market-based compensation package. The removal of incentive expense would therefore result in below-market compensation.

II. ANNUAL INCENTIVE PAY SHOULD NOT BE DISALLOWED

Q. Please summarize UAE witness Mr. Higgins' position on the Company's Annual Incentive Plan ("AIP") payments to employees.

A. UAE witness Mr. Higgins agrees that the cost of annual incentive compensation plans are appropriate when the compensation is "not excessive" and "not tied to utility financial performance, but rather to goals such as customer satisfaction, operating efficiency, and safety."[1] He recommends the Commission disallow the [redacted] percent of AIP that is related to the Company [redacted] percent) and [redacted] percent).

Q. Please describe PacifiCorp's compensation philosophy.

A. The Company's primary objective in establishing employee compensation is to provide pay at the market average. Compensation at the market average (competitive level) is critical to attracting and retaining qualified employees to support the business and our customers. To encourage employee performance, a certain percentage of each employee's market compensation must be "at risk." The Company's AIP is structured so that each employee has the opportunity to receive total compensation at the market average, so long as the employee performs at an acceptable level. In exceptional performance years, an employee's at-risk incentive may be more than target and in low performance years it may be below target, but on average, the at-risk incentive is generally at the guideline level. If the individual fails to earn the full guideline incentive, that individual will be paid less than the competitive total cash compensation in the marketplace for that year. Central to the Company's approach to total compensation is that, while certain employees may be paid more than or less than market in a given year as a result of the at-risk incentive portion of compensation, on an overall basis the base compensation and at-risk incentive will result in a level of compensation commensurate with the market. Stated another way, in the unlikely event

[1] Direct Testimony of Mr. Higgins, at lines 602-605.

every employee performed at exactly the same level, each employee would be paid only at the market average.

Q. What employees are eligible to receive AIP?

A. Non-union employees who are in an exempt status (salaried employees) are eligible to receive AIP, which is over 80% of the Company's non-union employees. Non-exempt or hourly employees are not eligible for AIP.

Q. Please describe how PacifiCorp determines how much AIP each employee receives.

A. The Company uses Company-wide and department goals, which are detailed in scorecards, to determine at-risk incentive payments. Each management-level employee has an individual scorecard by which their at-risk incentive payment is determined. Employees without an individual scorecard are judged based on the PacifiCorp scorecard and their department scorecard. An employee's individual at-risk incentive payment is then adjusted according to their manager's assessment of their performance, their contribution to the department, and company scorecards.

Q. How are scorecard goals determined?

A. Individual department managers establish specific business unit goals consistent with the core principles of the Berkshire Hathaway Energy family of companies, which have direct customer benefits. The six core principles are: (1) customer service; (2) employee commitment; (3) environmental respect; (4) regulatory integrity; (5) operational excellence; and (6) financial strength. [redacted] AIP compensation. Performance against scorecard goals is measured with Key Performance Indicators ("KPIs") that establish the measurable metric for success. KPIs are specific and measurable goals, such as achieving a certain reliability score or reducing the number of safety incidents. Business unit goals must advance the business and demonstrate continuous improvement over previous year goals.

Q. Please explain the customer benefits associated with each core principle.

A. [redacted] incentive-based compensation provided to the Company by Berkshire Hathaway. Each individual's AIP may be based on any combination of these factors.

Customer Service is based on delivering reliable and dependable service to customers at fair prices. This principle also includes providing exceptional service to customers. Customer satisfaction surveys comprise [redacted] of the total incentive-based compensation calculation, and approximately [redacted] of the Customer Service category. Keeping customer rates stable and as low as possible, while ensuring reliable service, provides a direct customer benefit.

Employee Commitment is based on preventing employee injury and workplace accidents, encouraging teamwork, and meeting goals related to employee engagement, training, and development plans. Ensuring that PacifiCorp's employees are safe, healthy, engaged with the company, and well-trained helps ensure that PacifiCorp operates safely and well. This in turn benefits PacifiCorp's customers.

Environmental Respect focuses on increasing investment in renewable energy, improving emissions rates and efficiency of fossil-fueled generation, offering resources to help customers manage their energy use, and investing in new transmission and distribution equipment to reduce the loss of kilowatts and improve reliability. Reducing emissions, increasing renewable resources, offering demand-side resources, and improving reliability provides a direct benefit to PacifiCorp's customers.

Regulatory Integrity is based on minimizing rate increases by achieving balanced regulatory and legislative outcomes. Achieving favorable regulatory outcomes and legislation that does not have adverse impacts to the Company or its customers directly benefits customers.

Operational Excellence is based on achieving transmission and distribution reliability goals. Operational Excellence is also based on optimizing availability factors for PacifiCorp's thermal and renewables fleets, and on ensuring PacifiCorp's electronic and physical assets are safe and secure. A reliable transmission and distribution system, transmitting power produced by generating assets that are performing at optimal levels, and whose electronic and physical assets are safe and secure undeniably provides a direct benefit to PacifiCorp's customers.

Financial Strength is based on achieving strong credit ratings and maintaining a high-quality, diversified portfolio of regulated businesses. A financially healthy and well-capitalized utility is able to obtain lower interest rates, which translates to lower costs for customers.

Q. If an employee received AIP less than the [redacted]% that Mr. Higgins recommends be disallowed, would their compensation be below market?

A. Yes. As I explained above, if an employee did not earn the full guideline incentive, that employee would be paid less than the competitive total cash compensation in the marketplace for that year.

Q. Is AIP considered a “bonus”?

A. No. It is critical to understand that the “at risk” portion of total compensation is not a bonus. A bonus is something unexpected. The “at risk” compensation is not unexpected—in fact, it is the opposite. The “at risk” portion of total compensation is expected by the employee, but only if the employee performs at or above an acceptable level. Any reduction beyond the competitive target incentive level would place the Company in a position of not being able to offer competitive pay levels and placing operational and customer objectives at risk.

Q. Do you agree with Mr. Higgins that financial performance goals do not benefit customers?

A. No. As explained in the cost of capital testimony of Ms. Nikki Kobliha, the Company is able to maintain its high credit rating and receive favorable terms on long-term debt as a direct result of its financial strength.[2] This includes its ability to earn its allowed return on equity and meet net income targets.

Q. Have other jurisdictions approved recovery of the Company’s AIP?

A. Yes. In docket UE-100749 Order 06, the Washington Utilities and Transportation Commission stated: “As we decided in the last litigated case, we conclude that the AIP is an appropriate method of implementing “incentive-based” compensation.”[3] The Commission acknowledged that the “at risk” component of compensation was “not a bonus or a level of pay in excess of the maximum compensation for a position. It is simply motivation for an employee to strive for the total compensation for his or her

[2] Cost of Capital Rebuttal Testimony of Ms. Kobliha, at lines 165-177.

[3] *Wash. Utilities & Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light Co.*, Docket UE-100749, Order 06, Final Order Rejecting Tariff Sheets; Authorizing Increased Rates; and Requiring Compliance Filing at 85 (Mar. 25, 2011).

position by achieving certain individual and group goals."[4]

Q. Has the purpose or structure of the Company's AIP changed since the Washington decision issued?

A. No.

Q. Do you believe that Mr. Higgins has presented a basis for disallowing any portion of the Company's at-risk incentive program?

A. No. As discussed above, AIP is designed to be an "at-risk" portion of total market compensation. To the extent AIP is tied to financial performance, those goals benefit customers.

III. CONCLUSION

Q. What is your recommendation?

A. I recommend the Commission reject UAE's proposed disallowance of a portion of employee's "at risk" AIP pay because AIP is not a "bonus" resulting in "excessive" wages to employees and financial performance goals benefit customers.

Q. Does this conclude your rebuttal testimony?

A. Yes.

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[4] *Id.*