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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

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. 24-035-04

ROCKY MOUNTAIN POWER'S REQUEST FOR REVIEW OR, IN THE ALTERNATIVE, REHEARING OF COMMISSION FINAL ORDER

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In accordance with the Order issued by the Utah Public Service Commission ("Commission") on April 25, 2025 ("Order") and Utah Code §§ 63G-4-301 and 54-7-15, PacifiCorp dba Rocky Mountain Power ("Company") submits this Request for Review or, in the Alternative, Rehearing of the Order in the above-captioned docket.

I. INTRODUCTION

The Order denies recovery of a substantial portion of the costs the Company has incurred and must incur to address Utah legislature-directed initiatives, mitigate customer risks, make needed investments, and provide affordable and reliable services to Utah's growing population. The Order is internally inconsistent and improperly denies the Company recovery of prudently incurred expenses. It also appears outcome-driven and frequently reaches conclusions that depart from statute and Commission precedent or that are unsupported or even contradicted by the evidence. Indeed, many conclusions in the Order cite no evidence at all or ignore evidence that was admitted in hearings when it would lead to a different result.

The Order undermines the state's long-standing history of regulatory steadiness, which compromises the financial stability of the utility and diminishes the ability of the Company to add the investments Utah needs to continue its economic growth in a safe and reliable manner. Increased and improved energy availability is indisputably in Utah's interests, as is increased wildfire safety. The Order deprives the Company—and Utah ratepayers—of the means to achieve those goals. As has been recently reaffirmed, independent studies consistently recognize that Utahns have among the lowest energy costs in the nation[1] and receive reliable electricity. Those benefits are not by happenstance. They have come from a regulatory environment that allows

[1] *See Utahn Pay the Lowest Rates in U.S. for Electricity, Even as One of the State's Biggest, Dirtiest Power Sources Declines*, Salt Lake Tribune (May 2, 2025); *Hawaii Is Beautiful, but It Costs a Lot to Keep the Lights On – Especially Compared to Utah*, Deseret News (May 19, 2025).

recovery of prudently incurred costs and that allows the utility to deploy the necessary capital to maintain a system without having to pay excessive financing costs. The Order is shortsighted and will undermine that environment.

The treatment of fire mitigation and excess liability insurance are just two examples where the Order is significantly out of step with prior Commission precedent, the evidence, and the reality of the risks facing the state, including our customers and the Company. The Order inexplicably recants the Commission's previous ruling that the Utah Code does *not* require a cost-risk analysis to support a wildfire protection plan under the Utah Wildland Fire Planning and Cost Recovery Act, Utah Code § 54-24-101 *et seq.* ("Act"), instead relying on the lack of a cost-risk analysis to reject the Company's proposed 2023 Revised Wildfire Mitigation Plan ("Plan"). It does so despite the fact that the Utah Division of Forestry, Fire, and State Lands ("FFSL") reviewed the plan and testified that it properly addressed the identified fire risks and was a prudent and reasonable plan.[2] The basis of the Commission's denial is that the Company allegedly failed to "prove" that the costs of mitigation are worth the benefits, an analysis that is at best subjective, particularly given that the Commission has not adopted any standard for making that assessment, and there is no industry-accepted approach for conducting such a cost-risk analysis.

Further, as discussed more fully below, the Order concludes that the Company has not shown that less expensive vegetation management would be insufficient (i.e., the Company must prove a negative). But that conclusion ignores significant evidence, including testimony by the Company and the FFSL showing that vegetation management is not sufficient in numerous areas and that commissions with significantly more experience and history with this issue, such as the California Public Utilities Commission, have found capital improvements to provide better

2 Hr'g Tr. at 269:10-13; 273:2-10; 280:11-18 (March 25, 2025) (Mike Melton testifying).

mitigation than vegetation management for many fire-risk areas. The Commission concludes that vegetation management is sufficient to protect Utahns from growing fire risks, without any support for that conclusion. Each of these aspects of the Order are inconsistent with the evidence presented in this proceeding and the Governor's own recent directives to strengthen wildfire preparedness.[3]

At the same time as the Order precludes the Company from recovering needed wildfire mitigation investments, it denies the Company recovery of its costs for excess liability insurance premium increases because it claims those increases were the result of the Company's failings, including proper mitigation of fire risk at issue in the *James* case. Such a ruling is demonstrably unsound and ignores record evidence that the *James* verdict did not cause the Company's premiums to increase, and that the verdict is on appeal and was based in substantial part on an incorrect assumption about the Company's role in the Santiam Canyon Fire. Specifically, the Oregon Department of Forestry ("ODF") completed a multi-year investigation that found the Company's operations and facilities *did not* contribute to the spread of the Santiam Canyon Fire. By ignoring record evidence that the Company is working to have the current verdict overturned, and has significant factual support in that effort, the Order improperly denies actual costs such as insurance on an assumption that those costs are the result of the Company's own bad acts.

The assumptions implicit in the Order also are internally inconsistent. It accuses the Company of failing to adequately mitigate risks (by assuming the *James* verdict is accurate) while simultaneously finding that the Company seeks to *over*-mitigate fire risks in Utah. These assumptions are dispelled by the unrebutted testimony that capital investment is needed to effectively support mitigation of fire risks in Utah. Further, the costs that *were* approved by the

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[3] Executive Order 2025-03, Governor Spencer Cox (Jun. 1, 2025), *available at* EO-Fire-Preparedness-04212025.pdf.

Commission for wildfire mitigation in the Order are demonstrably inadequate as they are based on the outdated 2020 Plan, which does not even address the increased Fire High Consequence Areas identified by the FFSL in 2023. The Commission fails to recognize the evolution of best practices and risk analysis that has occurred since the 2020 Plan.

The Commission's treatment of wildfire costs and insurance are merely examples of similar rulings in the Order that are at odds with past precedent. As discussed below, the Commission denied recovery for programs and processes it has previously approved as being in customer interests and that have remained unchanged since the last rate case. Furthermore, despite the Company fully complying with procedures this Commission has maintained in effect for decades for calculating test period amounts, the Order denies recovery of costs calculated in that long-established manner without any proper justification and without affording the Company discretion that is consistent with the prudence standard. There is no rational basis for the Commission to penalize the Company for following prior Commission directives. In fact, because the Company followed prior Commission orders, the current Order is all the more arbitrary and capricious. To add insult to injury, the Order's disallowance of the vast majority of the Company's costs comes at a time when the Company is experiencing financial pressures and when the state is looking to emphasize investments in energy and safety. Thus, the Order creates significant uncertainty and risk for the Company while, ironically, authorizing a lower ROE on the premise that the Company is less risky than it was in 2020.

While utilities have a basic obligation to provide service to their customers in a safe, reliable, and reasonable manner, regulators have a basic responsibility to balance customer and shareholder interests and may not arbitrarily or improperly force shareholders to pay costs that should be recoverable in customer rates. This "regulatory compact" is not a policy that a state can take or leave; it is constitutional. Here, the Order does not fairly weigh and apply factual evidence, ignores Commission precedent, is not consistent with applicable law, and, as a whole, appears outcome motivated to deprive the Company of legitimate and prudently incurred costs under the guise of controlling alleged out-of-control costs.

For these reasons, and as discussed in more detail below, the Commission should review the Order and revise it consistent with the information provided below, or, alternatively, grant a rehearing on the issues set forth in this request.

II. BACKGROUND

A. The 2023 Insurance Deferred Accounting Order Docket

The Company's requests regarding excess liability insurance ("ELI") premiums included: (1) recovery of approximately $82.0 million, Utah-allocated, in test year ELI premiums,[4] and (2) issuance of a deferred accounting order ("DAO") for approximately $104.4 million of incremental ELI premiums incurred since 2023 (Utah-allocated, excluding interest).[5] When the Company filed its request for a DAO in August 2023,[6] it sought to include all incremental ELI costs until these costs could be included in base rates.[7] The Company requested deferral of the incremental ELI premiums from 2023 to the date of new rates approved in this proceeding, and recovery of its test year insurance premiums, allocated to Utah using the System Overhead ("SO") factor.

The Commission denied deferral of the Company's ELI costs, finding that "[a]lthough such premiums are expenses of the kind that are ordinarily recoverable, available facts suggest this unprecedented increase is to some significant degree tied to conduct on the part of [the

[4] Phase III Rebuttal Testimony of Shelley McCoy at lines 31-35.
[5] *See id.* at lines 30-45; Phase III Rebuttal Testimony of Joelle R. Steward at lines 7-12.
[6] *See Application of Rocky Mountain Power for a Deferred Accounting Order Regarding Insurance Costs*, Docket No. 23-035-40 (original application filed August 21, 2023).
[7] March 20 Hr'g Tr. at 331:10-15 (McCoy).

Company]."[8] The order denying the DAO stated that the Commission "d[id] not prejudge whether RMP might ultimately demonstrate the increased ELI premiums are a prudent expense,"[9] but that the Company failed to make that showing in the DAO proceeding.

The Commission granted the Company's request for rehearing in May 2024.[10] Ultimately, the deferral request was consolidated for hearing into Phase III of this GRC proceeding, where the Commission would also address the recovery of the Company's Test Year ELI premiums.[11] In granting review of the DAO order, the Commission held that "the pertinent question" regarding recovery of deferred and Test Year ELI premiums "is whether RMP's tortious conduct in relation to the events underlying *James* . . . impacted RMP's ELI [Premiums] and to what degree."[12] ELI issues were heard by the Commission on March 20-21, 2025, as part of its Phase III hearings.

B. The 2023 Wildfire Mitigation Plan Docket

On September 25, 2023, the Company submitted its proposed 2023 Wildfire Mitigation Plan ("Plan"). On November 9, 2023, the FFSL, the state body tasked with monitoring and reducing fire risk in the state, provided its comments on the 2023 Plan and identified a number of areas of concern.[13] Based on those comments, the Company moved to vacate the schedule in the 2023 Plan docket (the "Wildfire Docket") so that it could reassess the 2023 Plan in light of the FFSL's comments. After subsequent discussions with FFSL and revisions to its modeling and analysis to address the FFSL's comments, the Company submitted the revised 2023 Plan on

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[8] Docket No. 23-035-40, Order Denying Application at 9 (Mar. 29, 2024).
[9] *Id.* at 14.
[10] *See* Docket No. 23-035-40, Order on Review (May 29, 2024).
[11] *See* Order Affirming Consolidation Order and Request for Comments Re: Alternative Process at 13 (Oct. 25, 2024).
[12] *Id.* at 14, referring to the jury verdict in the still-pending civil litigation matter *James v. PacifiCorp*, No. 20-CV-33885 (Cir. Ct. Multnomah Cnty., June 12, 2023) ("*James*").
[13] Utah Division of Forestry, Fire, and State Lands Comments, Docket No. 23-035-44 (Nov. 9, 2023).

February 28, 2024. On April 12, 2024, the FFSL submitted its comments on the Plan.[14] In those comments, the FFSL stated, in relevant part:

> Since the PSC issued its Order Granting Motion to Vacate Scheduling Order on November 21, 2023, RMP has met with and collaborated with the FFSL to address FFSL's input filed with the Commission on November 9, 2023. As a result, RMP has implemented substantial changes to its plan. Additionally, FFSL had the opportunity to review the revised plan in draft form and provided comments directly to RMP. Through this process and in ongoing discussions, RMP has improved its plan and has addressed FFSL's major concerns.
>
> . . . .
>
> FFSL has no additional input to the PSC regarding the substantive content of the revised plan. . . .[15]

The DPU and the OCS also submitted comments on the Plan. In its comments, the DPU recommended that the Commission "acknowledge Rocky Mountain Power's ("RMP") Revised 2023 Utah Wildland Fire Protection Plan ("February WFPP" or "Revised Plan") as complying with Utah Code §54-24-201" and also recommended "that an independent contractor be considered to evaluate the scope of RMP's Wildland Fire program to appropriately balance the costs of implementing the plan with the risk of potential wildland fire to achieve optimal program benefits while protecting Utah ratepayers."[16] In its comments, the OCS acknowledged that the Plan complied with all of the statutory requirements set forth in Utah Code § 54-24-201(2).[17] However, the OCS argued that the Commission should require the Company to "document, using an analytical basis, that costs and risks are appropriately balanced."[18] Because the Plan did not contain a cost-risk analysis, the OCS argued the Commission should not approve the Plan.

[14] FFLS Comments on Plan, Docket No. 23-035-44 (April 12, 2024).
[15] *Id.* at 1.
[16] Comments of Utah Division of Public Utilities, Docket No. 23-035-44 at 1 (May 10, 2024).
[17] Comments of Utah Office of Consumer Services, Docket No. 23-035-44 at 1 (May 10, 2024).
[18] *Id.* at 7.

On June 27, 2024, the Commission issued an Order for Additional Time and Process, in which it denied approval of the Plan "at [that] time" and ordered additional time and process be undertaken to consider the Plan.[19] Specifically, the Commission stated that, "[w]hile the record before us cannot support a finding the Revised Plan appropriately balances costs and risks, it similarly could not support a finding the plan fails to do so. The PSC simply requires more information."[20] As such, the Commission ordered that it would retain an independent evaluator to review the Plan and to provide a written report of its findings.[21] Significantly, the Commission did not order the Company to undertake any further action, let alone that the Company provide further information or further revise the Plan. Nor was the Company able thereafter to modify the Plan because it was under consideration by the Independent Evaluator ("IE") and the Commission. Thereafter, as explained below, the Commission consolidated the Wildfire Plan Docket into this proceeding.

C. The Company's 2024 General Rate Case Docket

As required by Utah Admin. Code R746-700-1(B), on January 24, 2024, the Company filed a Notice of Intent to File a General Rate Case and Request for Approval of Test Period on January 24, 2024, notifying the Commission and potential intervenors of its intent to file a general rate case.[22] As further contemplated by Utah Admin. Code R746-700-10(B), that notice requested Commission approval of a test period.[23] To support that request, on January 24, 2024, the Company

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[19] Order for Additional Time and Process, *Rocky Mountain Power's 2023 Wildland Fire Protection Plan*, Docket No. 23-035-44, at 8-9 (June 27, 2024).
[20] *Id.* at 9.
[21] *Id.*
[22] *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. 24-035-04, Rocky Mountain Power's Notice of Intent to File a General Rate Case and Request for Approval of Test Period (Jan. 24, 2024).
[23] *Id.* at 1.

submitted the Direct Testimony on Test Period of Shelley E. McCoy.[24] No party objected to either filing or to the Company's proposed test period.

On April 30, 2024, the Company filed its Update to Notice of Intent to File General Rate Case, indicating that its anticipated filing date for the general rate case would be on or before July 1, 2024.[25] The Company then filed its Application on June 28, 2024 ("Application").[26] With the Application, the Company submitted supporting direct testimony and significant filing requirements in accordance with Utah Administrative Code R746-700. Neither the Commission nor any other party challenged the completeness of the Application, and the Division of Public Utilities ("DPU") found the Application to be "substantially complete."[27]

On July 18, 2024, the Commission issued the Scheduling Order in this proceeding.[28] That order established an October 17, 2024 deadline for other parties to respond to the Company's Application.[29] It also set November 1, 2024 as the intervention deadline.[30] Further, it established a Phase I and Phase II testimony and hearing schedule, with all hearings concluded by January 17, 2025, allowing the Commission more than 30 days to issue a final order prior to the 240-day deadline set forth in Utah Code § 54-7-12(3)(a).[31]

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[24] Direct Testimony on Test Period of Shelley E. McCoy, Docket No. 24-035-04.
[25] *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. 24-035-04, Update to Notice of Intent to File General Rate Case (Apr. 30, 2024).
[26] *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. 24-035-04, Application for General Rate Increase (Jun. 28, 2024).
27 *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. 24-035-04, Comments from the Utah Division of Public Utilities at 1, 4 (July 12, 2024).
[28] Schedule Order, Notice of Hearings, and Notice of Public Witness Hearing ("Scheduling Order").
[29] *Id.* at 5.
[30] *Id.*
[31] *Id* at 3, 6.

On August 28, 2024, the Company filed an Amendment to the Application for General Rate Increase (the "Amendment").[32] The Company made that filing nearly two months before the deadline for parties to file direct testimony and before any party had filed any response to the Application. The Amendment did not replace the Application but modified two aspects of it. First, it eliminated a proposed second rate change of $285.2 million associated with net power costs ("NPC") that would have been effective January 1, 2026.[33] Second—as the Company had indicated that it would do in the Application—the Amendment updated insurance premium expenses to reflect the Company's then-most-recent policy period beginning August 15, 2024.[34] Other than these modifications, the relief sought by the Company remained unchanged.[35] The Amendment was supported by amended direct testimony from only four of the eighteen Company's witnesses who had filed direct testimony on June 28, 2024—the remaining testimony submitted with the Application was unchanged.[36] The Company's Amendment did not withdraw the Company's Application but was rather a modification to the Application.[37] The Company never treated the Application and the Amendment as separate filings, nor did it ever ask the Commission to do so.

No party objected to the Amendment, nor did the Commission or any other party object after the filing of the Amendment, take the position that the Amendment rendered the Application incomplete or that this docket should be considered to have restarted as of the date of the Amendment. Furthermore, no party stated that they could not respond to the Application, as amended, within the timeframes set forth in the Scheduling Order. In addition, neither the

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[32] *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. 24-035-04, Amendment to the Application for General Rate Increase (Aug. 28, 2024).
[33] *Id.* at 2.
[34] *Id.*
[35] *Id.* at 8-9.
[36] *Id.* at 6.
[37] *See* Utah Public Service Commission Administrative Procedures Act Rule R746-1-205.

Commission nor any other party claimed the Amendment restarted the 240-day deadline in Utah Code § 54-7-12, that it constituted a "new" or "separate" general rate case filing, or that a new Scheduling Order had to be issued.

On October 4, 2024, the Commission issued an Order (the "Consolidation Order") in which it ruled that insurance and wildfire issues raised in the Company's Application would be severed from this general rate case and be consolidated in two separate dockets: the DAO Docket and the Wildfire Docket, respectively.[38] The Consolidation Order permitted any party to the Consolidation Order to file an objection to it by October 11, 2024.[39]

On October 11, 2024, the Company filed its Objection to the Consolidation Order ("Objection").[40] In its Objection, the Company explained that Utah Code § 54-7-12 precluded the Commission from severing issues raised in this general rate case and consolidating them with the DAO Docket and the Wildfire Docket.[41] Among other things, the Company noted that severing issues from this case and consolidating them with other dockets would run afoul of the 240-day deadline required by Utah Code § 54-7-12.[42]

On October 25, 2024, the Commission issued its Order Affirming Consolidation Order and Request for Comments re: Alternative Process ("October Order").[43] In the October Order, the

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[38] *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. 24-035-04, Consolidation Order at 19 (Oct. 4, 2024).
[39] *Id.*
[40] *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. 24-035-04, Objection (Oct. 4, 2024).
[41] *Id.* at 6-12.
[42] *Id.* at 10.
[43] *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. 24-035-04, Order Affirming Consolidation Order and Request for Comments Re: Alternative Process (Oct. 25, 2024).

Commission reaffirmed its rulings in its Consolidation Order but proposed an alternative approach on which it asked the parties to comment. Specifically, it asked the parties to address the legal viability and practicality of consolidating the DAO and Wildfire Dockets into this proceeding.[44] It asked the parties to consider that approach instead of severing excess liability insurance and wildfire issues. One issue the Commission asked the parties to address was whether, when a utility "materially amends" a complete filing, "the PSC may issue an order 240 days after the date of the material amendment."[45]

On October 31, 2024, the Company submitted its Response to the October Order.[46] In its Response, the Company reiterated its view regarding the proper interpretation and application of Utah Code § 54-7-12, including its position that postponing a final decision in this proceeding until after the 240-day deadline was inconsistent with applicable statutes and rules.[47] Relying on the plain language of Utah Code § 54-7-12, the Company explained that the alternative approach could trigger the language of Utah Code § 54-7-12(3)(b), which would deem the Company's Application final.[48] In that respect, the Company explained that, if the Commission nevertheless elected to proceed with implementing a schedule that would postpone a ruling in this case until a date after the 240-day deadline, the Company "reserve[d] its rights to challenge this decision [the October Order] on appeal."[49]

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[44] *Id.* at 35.
[45] *Id.* at 36.
[46] *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. 24-035-04, Rocky Mountain Power's Response to Commission's October 25, 2024 (Oct. 31, 2024).
[47] *Id.* at 4-8.
[48] *Id.* at 8.
[49] *Id.*

On November 15, 2024, the Commission, over the Company's legal objections, issued its Order Adopting Alternative Process ("November Order").[50] In that order, the Commission rejected the Company's objections, including its interpretation of the § 54-7-12 and concluded: "On its face, the Statute allows the PSC 240 days to adjudicate a utility's proposed rate increase, and the PSC concludes the Statute allows 240 days to adjudicate a proposed rate increase regardless of whether the utility previously filed a materially different request."[51] It held that, "when a utility amends its initial pleading to propose a materially different rate change, as RMP has done here, the PSC concludes the Statute allows the parties the full 240-day period to adjudicate the new proposal."[52]

The same day it issued the November Order, the Commission issued its Scheduling Order for Consolidated Phase III and Notice of Hearing, in which the commission implemented a Phase III testimony and hearing process, and which contemplated a final order being issued in this proceeding in April 2025, well after the 240-day deadline.[53] That order set testimony dates for all Phase III testimony between February 7, 2025 and March 19, 2025, with the Phase III hearing to take place between March 25, 2025 and March 28, 2025.[54]

Thereafter, the Commission conducted a hearing on Phase I issues in December 2024, a hearing on Phase II issues in January 2025, and a hearing on Phase III issues in March 2025. The Order was issued on April 25, 2025.

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[50] *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. 24-035-04, Order Adopting Alternative Process (Nov. 15, 2024).
[51] *Id.* at 14.
[52] *Id.* at 19.
[53] *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. 24-035-04, Scheduling Order for Consolidated Phase III and Notice of Hearing at 1-2 (Nov. 15, 2024).
[54] *Id.* The hearing date was later divided into two hearing times, with insurance issues to be heard on March 20-21, 2025, and wildfire related issues to be heard on March 25-26, 2025. *See* Order Granting Unopposed Motion to Docket No. 24-035-04, Amend the Phase III Scheduling Order and Notice of Phase III Hearings (Jan. 23, 2025).

III. STANDARD OF REVIEW

Pursuant to applicable law, utility rates and charges must be just and reasonable, taking into consideration, among other things: "the cost of providing service to each category of customer, economic impact of charges on each category of customer, and on the well-being of the state of Utah; methods of reducing wide periodic variations in demand of such products, commodities or services, and means of encouraging conservation of resources and energy."[55] The Commission has discretion to set appropriate rates and rate designs that are (1) consistent with Utah law, (2) in the public interest, and (3) just and reasonable.[56] The burden is on the utility to propose rates, and utility "management decisions are generally accorded some deference, since management is most intimately involved in operating the utility and looking after the interests of customers, creditors, and owners."[57]

Utah Code § 54-4-4(4)(a) further provides that:

> If, in the commission's determination of just, reasonable, or sufficient rates, the commission considers the prudence of an action taken by a public utility or an expense incurred by a public utility, the commission shall apply the following standards in making its prudence determination:
>
> (i) ensure just and reasonable rates for the retail ratepayers of the public utility in this state;
> (ii) focus on the reasonableness of the expense resulting from the action of the public utility judged as of the time the action was taken;
> (iii) determine whether a reasonable utility, knowing what the utility knew or reasonably should have known at the time of the action, would reasonably have incurred all or some portion of the expense, in taking the same or some other prudent action; and
> (iv) apply other factors determined by the commission to be relevant, consistent with the standards specified in

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[55] Utah Code § 54-3-1.
[56] *Id*. § 54-4-4.1.
[57] *Mountain States Legal Found. v. Utah Pub. Serv. Comm'n*, 636 P.2d 1047, 1057 (Utah 1981).

this section.[58]

In assessing prudence under this statute, the Commission has long made clear that it "focus[es] on the reasonableness of the expense resulting from the action of the public utility judged as of the time the action was taken" and "determine[s] whether a reasonable utility, knowing what the utility knew or reasonably should have known at the time of the action, would reasonably have incurred all or some portion of the expense, in taking the same or some other prudent action."[59] The Commission does not "substitute [its] judgment in hindsight for the reasonable decisions made by management."[60] Similarly, a decision is not imprudent "merely because [the Commission] conclude[s] that a better, reasonable alternative was available for consideration or action."[61]

In other words, to demonstrate prudence, a utility need only demonstrate that, considering the relevant factors and information available at the time a decision was made, the utility made a *reasonable* decision. This standard does not require perfection, nor does it hold the utility to account for circumstances or information it could not know or foresee or for failing to adopt the "best" option. Nor does the prudence standard expect a utility to ignore legal requirements and obligations.

IV. ARGUMENT

A. The Commission Must Reverse Its Denial of the Plan and Its Disallowance of Deferred Wildfire Balancing Account Costs.

The Commission erred by declining to approve the Plan, which complied with the requirements of the Act, as well as standing Commission precedent interpreting the Act. The Order's holding, based on the Company's purported failure to satisfy a requirement that exists

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[58] Emphasis added.
[59] Utah Code § 54-4-4(4)(a)(ii)-(iii); *see also In re Application of Rocky Mountain Power*, 292 P.U.R.4th 1, 2011 WL 4430828, at *25 (Utah P.S.C. Sept. 13, 2011).
[60] *Id*.
[61] *Id*.

neither in the text of the Act nor in the Commission's prior interpretation of it, is a misapplication of the law. By imposing the new requirement that a plan include a cost-benefit analysis, the Order impermissibly "moves the goalpost" for the Company and other utilities seeking to develop plans in compliance with Utah law. In retroactively applying the new "required" risk analysis, the Order erroneously disapproved a plan that complies with applicable statutes, is prudent, and properly addresses wildfire risks. In that regard, the Order is arbitrary and capricious. It also imposed on the Company a standard the Company could not have known or foreseen when it proposed the Plan. And finally, the Order improperly denies the Company recovery of its deferred costs to implement the Plan.

1. The Order's Denial of the Plan Was Improperly Based on the Company's Alleged Failure to Include a Cost-Benefit Analysis.

The Act requires the Commission to approve a plan that "appropriately balances the costs of implementing the plan with the risk of a potential wildland fire."[62] PacifiCorp's Plan does that. And yet, throughout the Order, the Commission repeatedly and improperly conflated the requirement that a plan "appropriately[] balance" costs and risk with a "requirement" that a plan explicitly include some form of "adequate cost-benefit analysis."[63] The Commission claimed that a cost-benefit analysis is a "*plain, unambiguous statutory requirement*" and that "the record [does not] support a finding [that the Plan] appropriately balances cost and risk."[64] But the Commission's decision was not based on an assessment of whether the Plan appropriately balances cost and risk; rather, the ruling was based on a determination that the Company did not produce a formal, mathematical risk-cost analysis. The Commission's June 27, 2024 Order for Additional Time emphasized the lack of an "assessment of cost relative to risk," even though it claimed to have

[62] Utah Code § 54-24-201(2)(c)(ii).
[63] Order at 124.
[64] *Id.*

retained the IE for the purpose of "offer[ing] an opinion on the Revised Plan, including whether it appropriately balances costs and risks."[65] The Order is replete with references to the "fail[ure] to provide a cost benefit analysis,"[66] including citations to the IE Report's discussion of whether the Company conducted a risk-spend efficiency ("RSE") analysis.[67] And the Commission relied on other parties' complaints that the Plan did not provide an analysis to "justify" costs.[68] In short, the Commission's determination that the Company failed to produce an RSE or some other formalized cost-benefit assessment was central to its holding.

2. The Plan Was Not Required to Include a Cost-Benefit Analysis.

What the Commission's Order overlooked, however, is that no authority requires the Company to perform and provide such an analysis. The Commission inappropriately seeks to

[65] Order for Additional Time and Process, *Rocky Mountain Power's 2023 Wildland Fire Protection Plan*, Docket No. 23-035-44, at 8, 9 (June 27, 2024); *id.* at 7-8 ("[The Company] has provided no analysis to demonstrate any assessment of cost relative to risk."); *id.* at 8 (the Company "offers only conclusory statements without any analysis to support its representation" that the Plan appropriately balances cost and risk).

[66] Order at iv (Synopsis) ("The PSC finds that [the Company] failed to provide a cost benefit analysis."); *id.* at 121 ("the IE believes that [the Company]'s 'RSE analysis reasonably could have been expected to be included in the [2023 Plan] or soon after [its] publication.'"); *id.* at 125 (it was "abundantly clear [the Company] had not conducted an adequate assessment of cost-effectiveness . . . . Yet, even when [The Company] filed its written direct testimony, more than a month after the IE's Report issued, it contained no quantitative analysis whatsoever of cost relative to projected benefits."); *id.* (because the Company provided neither "mathematical-type analysis" or "meaningful qualitative assessment" but instead "nothing but assurances as to its internal processes for identifying risk, evaluating mitigation strategies, and responsibly managing implementation," "[t]he record does not allow the PSC, or other parties, to responsibly assess whether the cost of any particular mitigation measure is remotely commensurate with reduced wildfire risk").

[67] *Id.* at 121 ("[T]he IE's Report states that, as of January 2025, '[The Company] ha[d] not yet released an RSE analysis for the mitigation programs in its [2023 Plan].' . . . However, the IE believes that [the Company]'s 'RSE analysis reasonably could have been expected to be included in the [2023 Plan] or soon after [its] publication.'") (citing IE's Report at 41, 60); *id.* at 122 ("The IE opines that '[s]o long as [the Company] fails to provide a sufficiently detailed RSE, or other cost benefit analysis, it would be difficult for the Utah PSC to judge and evaluate the reasonableness of [the Company]'s expenditures . . . .'") (citing IE's Report at 41).

[68] Comments of Utah Office of Consumer Services, Docket No. 23-035-44 at 4 (May 10, 2024); Comments of Utah Division of Public Utilities, Docket No. 23-035-44 at 1, 7 (May 10, 2024); *see also* Hr'g Tr. at 68:21-69:1 (Mar. 26, 2025) (Jonathan Lee testifying that the "main reason" DPU recommended the Commission not approve the plan was "the lack of a cost-benefit analysis"); *cf.* Hr'g Tr. at 249:5-14 (Mar. 26, 2025) (Paul Alvarez testifying that UAE recommended the Commission deny approval because "the Company has not yet provided an analysis that appropriately balances the cost of implementing the 2023 Wildland Fire Protection Plan with the risk of potential wildland fires."); *id.* at 193:20-194:4 (The "fundamental problem" with [the Company]'s plan is that [the Company] did not "provide[] [a] cost-risk analysis").

impose a new requirement that is not found in the language of the Act and is contrary to the Commission's own prior interpretation of the Act.

a. The Act Does Not Require the Company to Submit a Cost-Benefit Analysis for a Wildfire Mitigation Plan to Be Approved.

Contrary to what the Commission suggests, the Act does not require the Plan to include a cost-benefit analysis.[69] Rather, the Act provides an extensive list of requirements a utility must satisfy, which does not include any quantitative or even qualitative risk analysis. It is certainly true that the Act provides that, for a plan to be approved, the Commission must find, "the plan: (i) is reasonable and in the public interest; and (ii) appropriately balances the cost of implementing the plan with the risk of a potential wildland fire."[70] But the Commission interpretated that very provision in its order approving the Company's 2020 Plan ("2020 Order") as not imposing any obligation on the Company to provide a cost-benefit analysis: "The Act does not require the Plan itself to expressly discuss and demonstrate that costs and risks are appropriately balanced. Rather, the Act requires the PSC to make such a finding, based on its review, in order to approve a plan."[71] The Commission's Order in this case is in stark contrast to that prior interpretation.

And in the Order addressing the Plan, the Commission acknowledged that "[t]he Act does not require the Plan itself to . . . demonstrate that costs and risks are appropriately balanced."[72] Yet that is exactly what the Order faults the Company for failing to do, i.e., demonstrate that costs and

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[69] *See* Order at 124 ("*It is a plain, unambiguous statutory requirement.*"); *id.* ("the Act, from its inception, flatly requires it").
[70] Utah Code § 54-24-201(2)(c).
[71] *Rocky Mountain Power's Utah Wildland Fire Protection Plan*, Docket No. 20-035-28, Order Approving Wildland Fire Protection Plan at 4-5 (Oct. 13, 2020) ("2020 Order"); *see also* Order for Additional Time at 7 ("[I]n approving [the Company]'s 2020 Plan, the PSC reasoned '[t]he Act does not require the Plan itself to expressly discuss and demonstrate that costs and risks are appropriately balanced' so long as 'the PSC [can] make such a finding, based on its review . . . .'"); Order at 127 (noting "the PSC concluded in the 2020 Plan Order that the Act does not expressly require 'the Plan itself' to make the demonstration provided the PSC can make the finding based on its review of the record").
[72] Order at 119.

risks are appropriately balanced. It does this despite all other parties acknowledging that the Plan—which did not include any such analysis—complied with the Act's statutory requirements.[73]

b. The Commission Has Never Before Required a Cost-Benefit Analysis.

Going against established precedent, the Commission now imposes a requirement that a plan sponsor provide its own formal evaluation of costs and risks to demonstrate that those costs and risks are appropriately balanced. As noted, the 2020 Order not only did not impose such a requirement but *expressly disclaimed* that a plan needed to provide such an analysis.[74] Nor did the Commission adopt a risk analysis requirement in its 2020 Commission rule, which reiterates the statutory balancing language with no additional burden.[75] Nor did the Commission request that the Company provide a cost-benefit assessment in its Order for Additional Time; instead, it ordered that it would "retain an independent evaluator to offer an opinion on the Plan, including whether it appropriately balances costs and risks."[76] Nothing in the Order for Additional Time, or any previous language from the Commission, took the position that the Company needed to conduct or provide a risk analysis. Without such notice or formal requirement, the Commission may not now reject the Plan on the basis that the Company failed to comply with the Act as written given the Commission's previously established standard.[77]

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[73] Comments of Utah Division of Public Utilities, Docket No. 23-035-44 at 7 (May 10, 2024) ("[T]he Division concludes that [the Company]'s filing . . . compl[ies] with Utah Code Annotated § 54-24-201."); Comments of Utah Office of Consumer Services, Docket No. 23-035-44 at 2 (May 10, 2024) ("The OCS has compared [the Company]'s Revised 2023 WFPP to the requirements in [the Act] and it appears that the plan contains information and a discussion of all the required topics."); IE Report 11-13 (noting that the Company was "compliant" with every section of Utah Code § 54-24-201(2)); *see also* Hr'g Tr. at 231:19-232:16 (Mar. 26, 2025) (Paul Alvarez testifying that the Act does not require cost-benefit analysis); *id.* at 198:1-199:6 (same).
[74] 2020 Order at 4-5; *see also* Hr'g Tr. at 52:13-17 (Jonathan Lee testifying that the Commission "approved the [2020] plan and was able to balance the costs and risks without a cost-benefit analysis . . ."); id. at 55:20-24 ("Can you tell me where in this order [approving the 2020 plan] there's any mention that the Company would be required in the future to submit a cost-benefit analysis?" "It's not in this order.").
[75] Hr'g Tr. at 240:18-241:5 (Mar. 26, 2025) (Paul Alvarez testifying that 2020 rule "uses the same . . . language . . . as the . . . legislation").
[76] Order for Additional Time at 9.
[77] Utah Code § 63G4-403(4)(d) & (h) (stating that an agency action is "arbitrary or capricious" if it is, for instance, "contrary to the agency's prior practice").

c. The Commission's Other Reasons Are Insufficient to Impose a Brand-New Requirement.

The Commission illogically claims that it may fundamentally alter the requirements for plan approval despite its prior contrary interpretation of the Act, contending that "the circumstances here are very different from the 2020 Plan Docket" and that the 2020 Plan was the first developed under the Act and that costs are much higher at present than they were at the time the 2020 Plan was submitted for review.[78] It claims the "context" of "substantial rate increases" is "plainly material" in assessing whether the Plan appropriately balances costs and risks.[79] But these concerns, alone or collectively, cannot supplant the plain language of the Act and the Commission's clearly articulated interpretation of the Act. The Commission cannot merely do as it did here and change its own prior interpretation of and practice under the Act.[80] Furthermore, it cannot claim to rely on an interpretation of its own rules for varying the application of the Act because, where an agency's rule conflicts with a governing statute, the rule is invalid.[81]

Thus, the Company reasonably relied on the standard articulated by the Commission in 2020 when preparing the Plan. And the Plan goes further in meeting the requirements of the Act and providing the Commission with the ability to make a finding that costs and risks are balanced than the 2020 Plan did by providing "more substantial, descriptive, and comprehensive" details.[82]

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[78] Order at 128-30.
[79] *Id.* at 129-130.
[80] Utah Code § 63G-4-403(4)(h).
[81] *Sanders Brine Shrimp v. State Tax Comm'n*, 846 P.2d 1304, 1306 (Utah 1993) ("It is a long-standing principle of administrative law that an agency's rules must be consistent with its governing statutes. Thus, a rule that is out of harmony with a governing statute is invalid."); *Mount Olympus Waters, Inc. v. Utah State Tax Comm'n*, 877 P.2d 1271, 1273-74 (Utah Ct. App. 1994) (holding an agency rule invalid because it sought to impose requirements beyond and contrary to what was included in the statute); see also Cf. Order at 128 ("the Act is the controlling authority").
[82] Rocky Mountain Power's 2023 Wildland Fire Protection Plan, Docket No. 23-035-44, Comments from the Division of Public Utilities at 3 (May 10, 2024) ("The February WFPP's structure remains fundamentally the same as the September 2023 WFPP, with 14 sections and various subsections, however, it is now more substantial, descriptive, and comprehensive in detail as it addressed the FFSL's November comments.").

3. The Commission's Decision Impermissibly Creates an Arbitrary Moving Standard That Is Impossible to Satisfy.

Not only does the Order impose a brand-new requirement that is contrary to the language of the Act and the Commission's prior orders, but it also creates an arbitrary and untenable standard that is impossible to satisfy. Despite its new holding that the Company is required "to provide a cost benefit analysis,"[83] the Commission still has provided no guidance on what kind of analysis would satisfy that requirement. The Company repeatedly requested that the Commission open a new docket to develop a process and procedures for assessing future plans submitted under the Act. Such guidance is necessary for approvable prospective plans.[84] The Order makes no comment on those requests.

The IE Report champions the use of a "risk-spend efficiency (RSE) analysis, which measures the cost of mitigation programs against realized or anticipated risk reductions directly attributable to the programs" and provides "an objective framework by which stakeholders can evaluate the appropriateness of mitigation programs and potential alternatives."[85] Appearing to endorse this view, the Order emphasizes the Company's failure to provide a "sufficiently detailed RSE."[86] But as the Company and other parties testified, an RSE is far from the industry-standard metric for evaluating the reasonableness of the cost of a wildland fire mitigation program, let alone assessing a cost-risk balance.[87] In fact, there is no "universally accepted approach" or "standard"

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[83] Order at iv (Synopsis).
[84] Jones Phase III Rebuttal at 28:575-591; Steward Phase III Surrebuttal at 1:12-2:24.
[85] IE Report 40-41.
[86] Order at 121-22.
[87] Hr'g Tr. at 114:9-21 (Mar. 26, 2025) (Bela Vastag testifying that there is disagreement over whether "an RSE . . . is a good cost-benefit analysis for assessing the prudence of spending ratepayer funds"); *id.* at 111:1-21 (stating that OCS does not have a position of what cost-risk analysis is required, only that "whatever Mr. Alvarez and Mr. Stephens [independent contractors for OCS] recommend, that's what the OCS is recommending Rocky Mountain Power use going forward"); Hr'g Tr. at 138:6-140:16 (Mar. 26, 2025) (Dennis Stephens testifying that RSE is an unacceptable metric and advocating for the "vastly superior risk informed benefit-cost analysis"); Hr'g Tr. at 100:13-22 (Mar. 25, 2025) (Joshua Jones testifying that a "mathematical-type analysis" and RSE are "not consistent with what we see in other jurisdictions or states or the wildfire community").

in the industry to make such an assessment, and the OCS's witnesses testified that an RSE was insufficient and not a proper analysis for such an assessment.[88] It is no surprise, then, that no other utility or cooperative has been required to submit a cost-benefit analysis as part of its plan for approval.[89] Nor is it a surprise that the Commission stopped short of selecting the RSE as a method that would satisfy the newly imposed requirement to provide a risk cost analysis. In its Order for Additional Time, the Commission merely held that the Company "must continue to make reasonable and responsible efforts to mitigate wildfire risk consistent with its 2020 Plan and its duties under all applicable law."[90] Yet the Order apparently concludes that the Company made no such efforts in the Plan without actually acknowledging the Company's substantial efforts to develop a comprehensive and compliant plan.

The Commission's attempt to impose, on a retroactive basis, a vague new requirement that is nowhere in the Act or its own prior orders creates a "moving target."[91] There is no assurance that any particular analysis will garner Commission approval or the approval of interested parties.[92] The lack of any articulated standard and the lack of any industry-wide consensus underscores the arbitrary and capricious nature of the Commission's break from its own precedent and the holding founded on a new but extremely vague standard.

As pointed out in testimony, such an analysis is necessarily subjective and susceptible to manipulation.[93] For instance, were the Company to simply conclude a human life is worth $100

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[88] Hr'g Tr. at 169:11-22 (Mar. 26, 2025) (Dennis Stephens testifying); Hr'g Tr. at 199:8-12 (Mar. 26, 2025) (Paul Alvarez testifying that "there isn't one approach . . . to balancing cost and risk, that is industry-accepted"); Phase III Direct Testimony of Paul J. Alvarez at lines 400-406; Phase III Direct Testimony of Dennis Stephens at lines 484-491; Hr'g Tr. at 201:2-10.
[89] Hr'g Tr. at 85:18-86:23 (Mar. 26, 2025) (Jonathan Lee testifying).
[90] Order for Additional Time at 10.
[91] Hr'g Tr. at 79:6-8 (Mar. 25, 2025) (Joelle Steward testifying); Hr'g Tr. at 182:11-15 (Joshua Jones testifying).
[92] Hr'g Tr. at 113:23-114:7 (Mar. 26, 2025) (Bela Vastag testifying).
[93] Hr'g Tr. at 150:16-152:16; 182:11-17 (March 25, 2025) (J. Jones testifying).

million, a plan that could potentially save only 10 lives suddenly justifies a $1 billion implementation price. This is why, as the testimony showed, mitigation plan requirements are being developed through deliberation in other states rather than through cost-benefit analyses.[94] In contrast, the Commission reverses its own course, moving against the trend of other states and utilities in rejecting the Plan.

4. The Record Supports That the Plan Complies with the Act.

The Commission erred by declining to approve the Plan because the record contains adequate evidence for approval under the Act. The DPU, OCS, and IE agree that the Company provided the information it was required to provide to comply with the Act.[95] The IE's Report further confirmed that the plan "sets forth significant and comprehensive programs to address . . . identified fire risks."[96] Indeed, the Plan appropriately balances costs and risks by treating high-risk areas, which represent only a small fraction of the overall risk areas, differently from the more extensive standard or lower risk areas. The high risk areas are appropriately targeted for more aggressive, and correspondingly more costly, mitigation efforts than the remainder of the risk areas where less extensive (and thus less costly) mitigation efforts are applied.[97] The FFSL concluded that the Plan satisfies the Act's requirements, properly and prudently assesses fire risks in the service territory, and proposes reasonable and prudent mitigation actions to address those risks.[98] The Commission erred by disregarding that evidence from the FFSL, which is the state body with expertise to evaluate and supervise fire mitigation efforts within Utah.[99] Rather than abide by the

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[94] Hr'g Tr. at 150:24-151:17 (March 25, 2025) (J. Jones testifying).
[95] *Supra* at 8; *see also* Phase III Testimony of Mike Melton at lines 27-28.
[96] IE Report at 4.
[97] Hr'g Tr. at 91:14-24; 95:13-98:23; 232:6-16; 232:25-233:3 (Mar. 25, 2025).
[98] Hr'g Tr. at 269:10-13; 273:2-10; 280:11-18 (March 15, 2025) (Mike Melton testifying); Melton Direct Testimony at lines 27-28.
[99] *See, e.g.*, Order at 123 n.263 (relegating to a footnote the acknowledgment that "[l]ike several parties, FFSL testified that the 2023 Plan contains the substantive statutory planning requirements").

language of the Act, the Commission never explains why it departs from the expert agency's findings, nor does it identify evidence to support its contrary conclusion that the Plan does not appropriately balance cost and risk. Instead of fulfilling its mandate as a regulator, the Commission appears to be setting new policy by merely insisting against record evidence and the State's designated expert agency that the Plan "burdens ratepayers with hundreds of millions in new capital spending" because the Company has not provided a cost-benefit analysis.[100]

But even that conclusion is inconsistent with the Commission's own prior statements. Specifically, in its Order for Additional Time, the Commission ruled, before receiving the Company's additional testimony and the IE Report, "While the record before us cannot support a finding the Revised Plan appropriately balances costs and risks, ***it similarly could not support a finding the plan fails to do so***. The PSC simply requires more information."[101] With the exception of the IE's conclusion that the Plan does not provide an RSE, the additional information provided after the Order for Additional Time by the IE Report, the Company, and the FFSL confirms that the Company's Plan was comprehensive, detailed, and complied with the requirements of the Act.[102] The principal reason cited in the IE Report for its recommended denial is that the Plan lacked an RSE, which as discussed above, is not required. Furthermore, the FFSL and the Company both provided information at hearing confirming that the Plan prudently balanced existing fire risks using various mitigation efforts proportionate to the attributes of specific areas and the different levels of risk.[103] The IE's discussion about the lack of a risk-cost analysis, which

[100] *See* Order at 129.
[101] Order for Additional Time and Process at 9 (emphasis added).
[102] Hr'g Tr. at 269:10-13; 273:2-10; 280:11-18 (March 25, 2025) (Mike Melton testifying); Phase III Testimony of Mike Melton; IE Report at 4, 10-14; Hr'g Tr. at 141:20-142:1 (March 25, 2025) (Stephens testifying); Phase III Direct Testimony of Joshua Jones; Phase III Rebuttal Testimony of Joshua Jones; Phase III Surrebuttal Testimony of Joshua Jones.
[103] *See Supra* n.102; *see also* Hr'g Tr. at 209:1-10 (March 26, 2025).

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is not required by the Act and has never before been required by the Commission, is not the type of new information or evidence that could justify the Commission in finding the Plan inadequate. For these reasons, the Commission's determination that the record does not provide substantial evidence that the Plan appropriately balances the costs and risks is flawed and contrary to both the evidence and the Commission's own prior decision.

5. The Order's Conclusion Is Not Supported by the Evidence.

The primary evidentiary rationale put forward by the Commission in its refusal to approve the Plan was the Company's alleged failure to prove a negative, i.e., that the less expensive mitigation effort of vegetation management would not provide an equally sufficient benefit as proposed capital improvements.[104] This conclusion ignores the evidence that was presented to the Commission.

First, the Company directly addressed this issue via witness Jones in Phase III. For instance, Mr. Jones testified that "vegetation management is not sufficient to adequately mitigate fire risk in high fire consequence areas because it does not remove all vegetation in those areas that act as fuel sources for wildfires, and removing all vegetation in such areas is impractical . . . ."[105] "[V]egetation management is important, but mitigation efforts should be tailored to address the specific risks, not just be where they are perceived to be the least expensive."[106] Jones also noted that the level of vegetation management in the Plan is consistent with plans of other utilities.[107] In fact, he explained:

[104] Order at 125-26.
[105] J. Jones Rebuttal at lines 302-305.
[106] *Id.* at lines 263-65.
[107] *Id.* at lines 267-307 (noting that PG&E is reducing its reliance on vegetation management in favor of increased facility investment); *id.* at 13:267-15:307 (noting that the California Public Utility Commission recently approved 1,230 miles of undergrounding and 780 miles of covered conductor installation in lieu of pure vegetation management).

> PG&E's original EVM program focused on expanded clearances, removing overhang four feet out from the lines and "up to the sky", and evaluation of any tree 272 tall enough to strike electrical lines, and removal of trees that did not pass the 273 evaluation. PG&E's EVM program resulted in significant pruning of trees to remove overhang and a significant volume of trees, including live trees, identified for removal well beyond typical vegetation management actions. However, that vegetation management approach has been determined to not be as effective in fire suppression, and PG&E has modified its approach.[108]

The Commission's conclusion that it cannot determine that capital investments to mitigate fire risk as requested by the Company are appropriate does not reference or refute the testimony offered by the Company. It does not explain why the Company's 85/15 ratio—with 85% of areas being mitigated with vegetation management and other less expensive mitigation efforts and 15% (i.e. the Fire High Consequence Areas) being mitigated through more aggressive means—is not a reasonable allocation of mitigation efforts. And there is no contradicting testimony in the record suggesting that vegetation management without the capital requested by the Company would be sufficient to mitigate the identified risks the FFSL confirmed needed to be addressed. Indeed, the OCS's witness on this issue admitted that he had no evidence that vegetation management would be adequate, and the Commission cites to no other evidence to support its view that vegetation management would be sufficient on a scale much broader than set forth in the Plan.[109] Furthermore, the FFSL also testified that vegetation management is not sufficient to mitigate all of the fire risks identified in the Plan.[110] Thus, the only testimony before the Commission on this topic is that burying or covering conductors is needed in addition to vegetation management. Ironically, the Commission's Order lacks a risk analysis and favors vegetation management instead of covered

[108] J. Jones Rebuttal at lines
[109] Hr'g Tr. at 201:23-204:3 (March 26, 2025) (Alvarez testifying).
[110] Hr'g Tr. at 289:6-24; 292:2-10; 293:1-294:3 (March 26, 2025) (Mike Melton testifying).

conductors because they are lower cost. There is no record analysis of the risks posed by dropping the covered conductors mitigation identified as a necessary protection against the risks identified in the Plan.

The Commission should revisit its decision to reject the Company's Plan based on the erroneous new requirement that the Company was required to submit a cost-benefit analysis. The record includes evidence demonstrating that the Plan prudently balanced costs and risks provided the Commission with the information necessary to under the Act to approve the Plan. The Commission's ruling denying the Plan, in contrast, is not based on record evidence. If the Commission wants to create new requirements or conditions for approval of a WMP, it must give adequate notice of those requirements, base them on appropriate statutory requirements, and apply them prospectively.

6. The Company Is Entitled to Recover Its Deferred Costs in the Wildfire Balancing Account and Should Have Been Permitted to Recover All of Its 2020 Plan Incremental Labor Costs.

Because the Plan complies with the Act, the Company's deferred costs to implement that plan should not have been disallowed. The Commission's only basis for disallowing those costs was its conclusion that "RMP does not allege it spent the Excess Deferred Plan Costs to implement the approved 2020 Plan. On the contrary, RMP has affirmatively represented it incurred them to implement the Plan. The PSC, therefore, concludes the Excess Deferred Plan Costs are not eligible for deferral and recovery under the Act."[111] Given that the 2023 Revised Plan should have been approved, the Company also should have been allowed to recover its deferred costs regarding the Plan.

[111] Order at 137.

In addition, the Commission's Order, concluding that RMP "cannot show" that incremental labor costs under the 2020 Plan are in fact incremental to base rates ordered in the 2020 GRC Order, is similarly flawed. The Company provided substantial evidence from Ms. McCoy and Mr. Berreth in which they explained both (a) that the 2020 deferred costs are in addition to, and therefore incremental to, labor costs included in the Company 2020 GRC test period costs, and (b) tracked separately from other base rate labor costs and, in that respect, not duplicative of other labor costs. For instance, Ms. McCoy, in her direct and rebuttal testimonies, showed that "bare labor has increased year over year" since 2020, which directly contradicts the claim that the labor costs at issue in the Company's request are not incremental.[112]

In addition, Mr. Berreth provided substantial detail showing that the Company had in fact differentiated between WMP labor-related costs and other labor costs to demonstrate that WMP labor costs since the 2020 GRC Order have increased and are, therefore, incremental to the amounts included in the 2020 GRC. As Mr. Berreth noted in his testimony, the Company conducted a review, by cost category, showing the amount of costs included in base rates as compared to the increased costs for 2021, 2022, and 2023, which showed that the cost increase amounts were incremental to the amount included in base rates.[113] The Commission's decision ignores this evidence on these costs and would impose an impossible standard on the Company before it could recover "incremental costs" under the Act.

112 McCoy Phase I Direct Testimony at 20:406-22:441; McCoy Phase I Rebuttal Testimony at 81:1678-81.
113 Berreth Phase I Direct Testimony at 9:157-166 & Exhibit RMP_(ALB-2); Berreth Phase I Rebuttal Testimony at 4:71-7:114; Berreth Phase III Rebuttal Testimony at 4:78-6:124.

B. The Commission Disallowance of the Lion's Share of the Company's Excess Liability Insurance Premiums Is Unsupported and Improper.

1. <u>The Company's Requests for Relief and the Commission's Determinations in the Order Regarding Recovery of Excess Liability Insurance Premium Expenses.</u>

a. The Company's request for deferral and recovery of premiums for excess liability insurance premium expenditures.

The Company's requests regarding excess liability insurance ("ELI") premiums included: (1) recovery of approximately $82.0 million, Utah-allocated, in test year ELI premiums,[114] and (2) issuance of a deferred accounting order ("DAO") for approximately $104.4 million of incremental ELI premiums incurred since 2023 (Utah-allocated, excluding interest).[115] When the Company filed its request for a DAO in August 2023,[116] it sought to include all incremental ELI costs until these costs could be included in base rates.[117] In August 2023, the Company had procured its August 2023-August 2024 ELI policies, and, in August 2024, the Company obtained new policies (with an 18-month term). The Company requested deferral of its incremental ELI costs as it did in 2023, and those costs increased while the DAO request was pending. The Company requested deferral of the incremental ELI premiums from 2023 to the date of new rates approved in this

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[114] The Company requested the test year insurance premiums be recovered through the proposed Insurance Cost Adjustment ("ICA") or, if the ICA is not adopted, recovery in base rates. Phase III Rebuttal Testimony of Shelley McCoy at lines 31-35.
[115] *See id.* at lines 30-45; Phase III Rebuttal Testimony of Joelle R. Steward at lines 7-15, March 20 Hr'g Tr. At 306:15-22; 315:5-7 (McCoy) ("This deferral balance represents amounts paid by the Company incremental to those in rates for the policy period covering August 15, 2023, through August 15, 2024, of $49.5 million Utah allocated, and incremental amounts paid for the policy period beginning August 15, 2024, through the end of April 2025, of $54.9 million Utah allocated." The end of April 2025 was used in the calculation to estimate when new rates would go into effect following the conclusion of this proceeding.
[116] *See Application of Rocky Mountain Power for a Deferred Accounting Order Regarding Insurance Costs*, Docket No. 23-035-40 (original application filed August 21, 2023).
[117] March 20 Hr'g Tr. at 331:10-15 (McCoy).

proceeding, and recovery of its test year insurance premiums, allocated to Utah using the System Overhead ("SO") factor.

b. The Order's provisions regarding recovery and deferral of ELI premiums.

The Order authorizes the Company to recover $11,662,802, Utah-allocated, in ELI premiums.[118] The Commission also denied the Company's request for a deferral of the approximately $104.4 million, Utah-allocated, of incremental ELI premium expenditures that were the subject of the Company's request for a DAO filed in 2023.[119] In all, the Order denies the Company the opportunity to recover in rates approximately $174.7 million in premiums paid by the Company for ELI policies since 2023. The Company's requests and the outcomes authorized in the Order are summarized in Table 1:

Table 1: Summary of Company ELI requests and outcomes in the Order

Expense Category	**Company Request**	**Recovery authorized**
Test Year ELI Premiums (Total Company)	$187,500,000	26,231,364
Test Year ELI Premiums (Utah Allocated)	$82,000,000	$11,662,802
Percentage State Allocation	44.25% (SO Factor)	44.25%
Deferred Accounting Request	$104,000,000	$0

The Commission disallowed "$70.4 million in costs related to ELI insurance[.]"[120] The approximately $11.7 million of authorized ELI premiums are "based on the ELI costs in the 2020 GRC, updated to reflect commensurate recent premium increases of peer utilities in Nevada and Colorado that have liability risk and wildfire history similar to Utah."[121] To arrive at the "updated"

[118] *See* Order at 111.
[119] *Id.* at 169.
[120] *Id.* at iii.
[121] *Id.*

amount, the "PSC multiplied the sum approved for ELI Premiums in the 2020 GRC [$6,557,841] by 400 percent to reflect an increase commensurate with peer utilities that have not experienced catastrophic wildfire events and then calculated Utah's allocation using the standard methodology for this account."[122]

The Order bases the Test Year ELI premium disallowance of $70.4 million on the Commission's findings that the bulk of the Company's ELI premiums were imprudent. The prudence inquiry, the Order holds, "includes not only RMP's actions with respect to *James*[123] and other fires, but RMP's response to the skyrocketing premiums, its decision to purchase commercial insurance on the terms that it did, and its request to allocate a plurality of the associated costs to Utah ratepayers."[124]

The Commission's factual and legal determinations on each of these issues are not supported by substantial evidence, and, in many cases, are based on plainly erroneous information or calculations. In addition, the Order is inconsistent with the legal and evidentiary standards the Commission established in its own orders for reviewing the prudence of ELI premiums in this proceeding. The Commission's Order affords the Company no discretion on any of its insurance decisions and in at each point, substitutes its own judgment for that of the Company. That is not consistent with the Commission's own long-standing articulation of the prudence standard.

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[122] Order at 166 n.379. The Order contends that the 2020 GRC amount multiplied by 400 percent equals $26,231,364. The Order does not state what the "standard methodology for this accounting" is, but the Company assumes it would involve application of the SO Factor included in the 2020 Protocol. Application of the SO Factor appears to have resulted in the approved Utah-allocated ELI premium of $11,662,802. As detailed herein, the $6,557,841 starting point used in the Order is not "the sum approved for ELI Premiums in the 2020 GRC." The ELI premiums approved in the 2020 GRC total $10,486,564.

[123] *James v. PacifiCorp*, No. 20-CV-33885 (Cir. Ct. Multnomah Cnty., June 12, 2023).

[124] Order at 160.

2. <u>The Order applies legal and evidentiary standards that are inconsistent with prior Commission Orders that are directly applicable to this proceeding. Rehearing or reconsideration is required to enable the Company to present additional evidence to address the Order's announcement of different standards applicable to this proceeding.</u>

In the DAO proceeding, the Company requested to defer incremental ELI premium expenses incurred above the levels authorized in the Company's general rate case ("GRC") in 2020. The Commission denied deferral of the Company's ELI premiums, finding that "[a]lthough such premiums are expenses of the kind that are ordinarily recoverable, available facts suggest this unprecedented increase is to some significant degree tied to conduct on the part of [the Company]."[125] The Commission rested this finding entirely on the contention that the increase in the Company's insurance premium expenses resulted from the jury verdict against the Company in *James*.[126] The order denying the DAO stated that the Commission "d[id] not prejudge whether RMP might ultimately demonstrate the increased ELI premiums are a prudent expense,"[127] but that the Company failed to make that showing in the DAO proceeding.

The Company requested rehearing in April 2024.[128] In granting review, the Commission detailed the legal standard for the evidentiary showing that would be necessary for the Company to overcome the DAO order's conclusion that "available facts suggest" the increases were tied to the Company's conduct during the 2020 wildfires litigated in *James*.[129] The Commission further elaborated the legal standard for establishing the prudence of Test Year and deferred ELI expenses in its orders consolidating the DAO issues into this GRC proceeding:

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[125] *Application of Rocky Mountain Power for a Deferred Accounting Order Regarding Insurance Costs,* Docket No. 23-035-40, Order Denying Application at 9 (Mar. 29, 2024).
[126] *Id.* at 12.
[127] *Id.* at 14.
[128] *See* Order on Review at 2.
[129] *Id*. at 12.

- The pertinent question is whether RMP's tortious conduct in relation to the events underlying *James* . . . impacted RMP's ELI [Premiums] and to what degree.[130]

- [T]he PSC granted RMP's request for rehearing for the purpose of reopening the evidence concerning whether and to what extent RMP's liability stemming from a landmark adverse jury verdict in Oregon caused the increase in ELI Premiums.[131]

- The impact of *James* on RMP's ELI Premiums is a central question both here and in the DAO docket.[132]

- RMP has long been on notice that its increased ELI Premiums could not be adjudicated without the PSC determining whether and to what extent its tortious conduct in *James* is the cause of the increase.[133]

The Company followed the Commission's directives and presented evidence that it was not the "tortious conduct" alleged in *James* that caused insurers to increase its premiums in 2023 and beyond.[134] The Commission, however, shifted its justification for denying the Test Year costs to an unsupported finding that the Company's use of insurance to pay non-James-related claims rendered the ELI premiums imprudent. It is arbitrary and capricious to hold that use of insurance to cover claims, which is exactly what insurance is for, is imprudent. The Order recognizes the record evidence that "RMP had already exhausted its [2020 ELI] coverage such that no claim associated with *James* contributed to its loss history."[135] The evidence presented by the Company established that insurers did not consider the tortious conduct alleged in *James* when setting the Company's ELI premiums.[136] In addition, the Company has appealed the circuit court jury verdict

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[130] *Id.* at 14.
[131] November Order at 3.
[132] October Order at 13.
[133] *Id.* at 26.
[134] *See generally*, Phase III Direct, Rebuttal, and Surrebuttal Testimony of Mariya V. Coleman and Confidential Exhibit MVC-1.
[135] Order at 161.
[136] *See, e.g.*, March 20 Hr'g Tr. at 75:14-22 (Coleman) ("[T]he *James* verdict had no impact on the Company's excess liability insurance costs, other than to serve as one more example of the increasing risk of wildfire claims to all electric utilities and reinforce the industry-wide concerns of insurers about this risk. The Company's insurers have never pointed to the negligence verdict in *James* as the cause of the Company's excess liability insurance premium increases since 2023."); *Id*. at 76:16-23 (Coleman) ("To be clear, the Company does not dispute that large

in *James*,[137] and contests the verdict's liability and damages findings. Moreover, the factual underpinnings of many of the *James* liability findings have been undermined by a recent Oregon Department of Forestry report that investigated the causes of the fires that are the subject of the *James* litigation.[138]

The Commission did not, however, reach what it stated was the "pertinent question,"[139] the "central question,"[140] and "purpose of reopening the evidence"[141] on recovery of ELI premiums. The Order makes no findings on whether "RMP's tortious conduct in relation to the events underlying *James*"[142] or "RMP's liability stemming from a landmark adverse jury verdict in Oregon caused the increase in ELI Premiums."[143] Rather, the Order shifts to a new prudence standard only announced in the Order.

The standard—identified for the first time in the Order—focuses primarily on what it calls "discrepancies" between the Company's ELI premiums and those of other utilities. While citing the *James* verdict and the exhaustion of RMP's coverage for other claims as a potential cause, the Order justifies its denial by "the discrepancy" between RMP and other allegedly comparable utilities.[144] But the record does not establish that this is a proper standard for determining whether the ELI premiums are prudent, whether the utilities' premiums are, in fact, appropriate for comparison, and even if they are, whether the Company was imprudent in relying on its insurance

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jury verdicts outside of an insured's loss history, such as the *James* verdict, are noticed by insurers. However, insurers take note of these verdicts, not to pass judgment on whether a particular [c]ompany has been negligent, but rather to have accurate information about the legal environment to which all utilities are exposed.").

137 March 20 Hr'g Tr. at 53:13-16 (Coleman).

138 *See* RMP Cross Exhibit 7, Oregon Department of Forestry Santiam Canyon Wildfire Event Incident Investigation Report (March 19, 2025).

139 Order on Review at 14.

140 October Order at 13.

141 November Order at 3.

142 Order on Review at 14.

143 Order Adopting Alternative Process at 3.

144 Order at 161.

to cover non-*James* claims. Yet it is because of the perceived and unexamined "discrepancies" that the Order disallowed over $70 million of Test Year ELI premiums and denied deferral and recovery of over $100 million of ELI premiums incurred since 2023.

Elsewhere in the Order, the Commission returns to its claim that ELI premiums "were driven far beyond industry norms for Utah, by PacifiCorp's management of the wildfires in September 2020."[145] As noted above, the record shows the "tortious conduct" alleged in *James* did not impact the premiums. The Order also implies the "management" decision to use the Company's insurance to pay the extraordinary level of non-*James* claims that arose in 2020 was imprudent. Yet there is no explanation, or reference to record evidence, in the Order for why using insurance to pay large wildfire claims constitutes imprudent "management" by the Company. The evidence showed that insurers will increase future premiums for insureds on whose behalf the insurers have covered large claims.[146] However, there is no basis for finding payment of those increased claims, standing alone, was an imprudent action by the Company.

The Order's holding on the Company's continuing request for deferral of ELI premiums relied on the same rationale regarding purported "discrepancies" with the ELI premiums paid by other utilities.[147] The Order applied the same logic used to disallow the bulk of Test Year ELI premiums to deny the deferral request in its entirety. In fact, the deferral decision doubles down on the 400 percent multiplier to establish prudence and recoverability of the Test Year expenses. The use of the 400 percent multiplier is, for reasons detailed herein, contrary to the record evidence and arbitrary as applied to the Company.

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[145] *Id.* at iii.
[146] *See id.* at 147.
[147] *Id.* at 169 ("Given our findings above regarding RMP's failure to show its astonishing increases in excess liability insurance premiums are a prudent expense, it has not shown a likelihood of recovery existed.").

For the deferral, the Order relied on its holding that ELI premiums could only increase by 400 percent for the Test Year to justify that ELI premiums should only ever be recoverable up to the 400 percent limit.[148] Based on that assumption, the Order found that "the evidence does not support a finding that the 400 percent increase (from the 2020 GRC) we approve here, if applied to the premiums RMP paid in the deferral period, would constitute an 'extraordinary' increase requisite to satisfying the *MCI* exception."[149]

The Order provides no basis for finding that a 400 percent increase in an expense item is *per se* not "extraordinary," and cites no Commission precedent in a deferral proceeding for such a finding. It is notable that the record includes evidence of other utilities in Western states that experienced ELI premium increases *below* the 400 percent threshold (Avista and Idaho Power)[150] and had ELI premium deferrals approved by the Idaho and Washington commissions.[151]

In considering requests for review, the Commission has previously applied the Utah Administrative Procedures Act ("APA") standard for judicial review, which states that an agency conclusion may be reversed for several reasons, including if the agency's action is "contrary to the agency's prior practice, unless the agency justifies the inconsistency by giving facts and reasons that demonstrate a fair and rational basis for the inconsistency"[152] or is "otherwise arbitrary or

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[148] *Id.*
[149] *Id.*
[150] DPU's testimony notes that: "Avista experienced growth of 100% from 2020/21 to 2022/23, and Idaho Power experienced growth of 100% for the entire period from 2018/19 to 2022/23." *See* Phase III Amended Direct Testimony of Jeffrey S. Einfeldt, at lines 190-192 ("Phase III DPU Einfeldt Direct").
[151] *See* Phase I Direct Testimony of Frank Graves at lines 621-49 ("Phase I RMP Graves Direct"). Mr. Graves's testimony discusses the decisions in: (a) Washington Utilities and Transportation Commission Docket Nos. UE-220053, *et al.*, Final Order 10/04 (Dec. 12, 2022) (Avista); and (b) Idaho Public Utilities Commission Case No. IPC-E-21-02, Order No. 35077 (June 17, 2021).
[152] Utah Code Ann. § 63G-4-403(5)(h)(iii); *see also In the Matter of the Application of Rocky Mountain Power for Approval of an Electric Service Agreement between Rocky Mountain Power and Praxair, Inc.*, Docket No. 10-035-115, Report and Order at 10 (Dec. 16, 2010) (citing and applying standard regarding consistency with prior agency practice).

capricious."[153] When considering a claim that an agency's order is arbitrary or capricious, the Utah APA applies a reasonableness standard,[154] which Utah courts have described as "essentially a test for logic and completeness rather than the correctness of the decision."[155] Additionally, a party challenging an agency's conclusion on the basis that the agency's action is inconsistent with past practices must demonstrate that they were "substantially prejudiced" by the inconsistent action,[156] meaning there is a "reasonable likelihood that the error affected the outcome of the proceedings."[157]

The Order abandoned the legal and evidentiary standards the Commission identified in the DAO Order on Review and subsequent orders in this docket regarding the causes of ELI premium increases. RMP was substantially prejudiced by the inconsistency between the standards required in prior Commission orders and the new standards applied in the Order. Moreover, as discussed here, the Commission's application of the new and inconsistent prudence standard for ELI premiums was applied to the Company in ways that are contrary to or unsupported by the record. The inconsistent application of standards applied by the Commission certainly "affected the outcome of the proceedings": it provided the flawed logic underlying the Commission's decision to disallow recovery of unreasonable amounts of the Company's costs, all of which were expended to purchase ELI policies that are necessary to the prudent operation of its business in Utah and every other state where it provides service.

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[153] Utah Code Ann. § 63G-4-403(4)(h)(iv).
[154] *Bourgeous v. State Dep't of Com.*, 2002 UT App 5, ¶ 7.
[155] *Murray v. Utah Labor Comm'n*, 2013 UT 38, ¶ 32.
[156] Utah Code Ann. 63G-4-403(5); *Petersen v. Utah Labor Comm'n*, 2017 UT 87, ¶ 8.
[157] *Smith v. Dep't of Workforce Servs.*, 2010 UT App 382, ¶ 17 (quoting Morton Int'l, Inc. v. Utah State Tax Comm'n, 814 P.2d 581, 584 (Utah 1991), *overruled*, *Murray v. Utah Labor Comm'n,* 2013 UT 38, ¶ 22, *as recognized in Ellis-Hall Consultants v. Public Serv. Comm'n*, 2016 UT 34, ¶ 22)..

When considering a party's request for rehearing or reconsideration, the Commission has applied Utah R. of Civ. P. 59,[158] which governs civil motions for new trials. Utah R. of Civ. P. 59 identifies several bases for a new trial, including (1) accident or surprise that ordinary prudence could not have guarded against; (2) insufficiency of the evidence to justify the verdict or other decision; and (3) that the verdict or decision is contrary to law or based on an error in law.[159] The Commission must reconsider its ELI finding because of its "surprise" shift in legal and evidentiary standards regarding the prudence of ELI premium expenditures. In addition, the disallowance of ELI premiums and denial of the deferral were not justified by the evidence but rather by erroneous application of the law.

3. <u>The Order relies on comparisons of percentage increases of ELI premiums among utilities that are based on incorrect, misleading, or inapposite calculations of the data in the record. The 400 percent multiplier used in the Order to calculate the Company's ELI premiums is not supported by the record and is arbitrary and capricious as applied to the Company.</u>

The Order does not base its determination of the amount of ELI premiums the Company may recover in Utah rates on the actual ELI premiums paid by the Company. Nor does the Order find that the type, quality, or amount of ELI coverage the Company purchased was unreasonable in light of potential liability risks the Company faces. In addition, the Commission departs from its precedent of holding that ELI and other insurance policies are prudent expenditures for the Company.

Rather than rely on data specific to the Company and current ELI risks and costs, the Order establishes the amount of recoverable ELI premiums by stepping up the Company's approved 2020 ELI premiums by 400 percent. This calculation results in a total recoverable Utah-allocated ELI

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[158] *See, e.g., Pacific Energy & Mining Company*, Docket No. 18-2602-01, Order on Review at 1-2 (May 2, 2019).
[159] Utah R. Civ. P. 59(a)(3), (6), (7).

premium of $11,662,802 for the 2025 Test Year.[160] The Commission justified the 400 percent adjustment by asserting that it is: (a) "commensurate with recent premium increases of peer utilities in Nevada and Colorado that have liability risk and wildfire history similar to Utah";[161] and (b) based on the DPU "comparative analysis with the increases other utilities have experienced[.]"[162] The DPU analysis resulted in a recommendation that "the PSC limit RMP's increase to between 100 and 400 percent of the amount currently in base rates from the 2020 GRC."[163]

Both of the Order's conclusions are based on data or calculations that the record shows are incorrect, used without proper context, and otherwise "not supported by substantial evidence in light of the entire record."[164] In particular, the 400 percent calculation is based on comparisons of the Company's circumstances with those of other Western utilities, but includes five critical factual errors.

Factual Error 1: The Order erroneously identified the amount of ELI premiums approved for recovery in the 2020 GRC. The Order states its intention to apply a 400 percent increase to the amount of the Company's ELI premiums approved in the 2020 GRC Order.[165] The Order contends that amount is $6,557,841 (total-Company). That figure, however, is actually the amount the Company proposed to recover when it filed direct testimony in the 2020 GRC.[166] During the GRC

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[160] *See* Order at 111 and 166 & n.379.
[161] *Id.* at iii.
[162] *Id.* at 159.
[163] *Id.* at 159 n.366 (citing March 21, 2025 Hr'g Tr. at 213:15-18).
[164] *Formal Complaint of Ronda and Martell Menlove against Bridgerland Water Co.*, Docket No. 23-001-03, Order on Request for Review at 2-3 (Dec. 29, 2023) (citing Utah Code Ann. §§ 63G-4-403(4)(d) and -403(4)(g)).
[165] *See* Order at 166 n.379.

[166] *See 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. 20-035-04 ("2020 GRC"); RMP Direct Testimony of Steven R. McDougal, Exhibit RMP__(SRM-3), at 4.4.3 (May 2020).

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proceeding, the Company updated its requested recovery for ELI premiums, to $10,486,564.[167] When the Commission issued its order in the 2020 GRC, the Commission approved recovery of the premiums in the Company's update as part of the "undisputed adjustments" approved in the order.[168] The Company urges the Commission to reconsider the 400 percent multiplier used to establish ELI premiums in the Order. Nevertheless, if the Commission does not reconsider adoption of the 400 percent multiplier, it should be applied to the number that is actually "the sum approved for ELI Premiums in the 2020 GRC."[169] This correction alone would increase the Company's recoverable Test Year ELI premium by over $7,000,000.[170]

Factual Error 2: The 400 percent increase approved by the Commission is not commensurate with the identified peer utilities. The Commission stated that the 400 percent increase for RMP is intended "to reflect commensurate recent premium increases of peer utilities in Nevada and Colorado that have liability risk and wildfire history similar to Utah."[171] The Commission's conclusions are based on data from Public Service Company of Colorado (PSCo) and NV Energy provided in testimony submitted by Western Resource Advocates (WRA).[172] WRA's conclusions are quantified in a workpaper entitled "WRA Boothman Phase III Workpaper" ("WRA Workpaper"), which was attached to its Phase III direct testimony.[173]

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[167] *Id.*, Exhibit RMP__(SRM-2R), at 66 ("Insurance Premium Update").
[168] *Id*, Order at 51, Table 3 (The table "presents the impacts of our decisions … on RMP's requested revenue requirement."). The adjustment for ELI premiums presented in Table 3 reflects use of the $10,486,564 figure referenced above rather than the $6,557,841 that the Order states is the approved ELI premium.
[169] Order at 166 n.379.
[170] If the $10,486,564 premium amount is multiplied by 400 percent, the resulting ELI premium is approximately $42 million (total-Company). The Utah allocation (44.25%) would be approximately $18.6 million.
[171] Order at iii.
[172] *Id.* at 151-52.
[173] *See* Phase III Direct Testimony of Karl G. Boothman on Behalf of Western Resource Advocates at 1 (Feb. 7, 2025) (List of Attachments) ("WRA Direct").

As noted in the Order, the WRA Workpaper includes premium amounts for PSCo and NV Energy, as well as other utilities.[174] However, the data in the WRA Workpaper does not support the conclusion that PSCO and NV Energy only experienced a 400 percent increase in ELI premiums. Table 2 shows the actual increases for both utilities from 2020 and 2024.[175]

Table 2: NV Energy and PSCo ELI Premium Percentage Increases

Utility	State	2020 ELI Premiums	2024 ELI Premiums	Percentage Increase
NV Energy	Nevada	$2,647,779[176]	$54,343,448[177]	1,953%
PSCo	Colorado	$5,136,747[178]	$49,386,384[179]	862%

The record evidence shows the 2020-2024 percentage increase in ELI premiums for PSCo is more than double, and NV Energy's premium increase is almost five times the 400 percent increase the Order applied to the Company.

While the Order cites PSCo and NV Energy as "peer utilities," which are "subject to many of the same or similar drivers of wildfire risk, such as climate-induced drought, elevated temperatures … high winds[,] etc.,"[180] the outcome of the Order sets ELI premiums for the Company at a level tens of millions of dollars lower than ELI premiums paid by PSCo and NV Energy, as summarized in Table 3:

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[174] Order at 152.
[175] The year 2020 is chosen because it is the ELI policy period for the Company's ELI premiums that are multiplied by 400 percent in the Order to determine recoverable Test Year ELI premiums.
[176] WRA Workpaper, line 9, column I (reporting "Annualized Premiums" for NV Energy for 2020).
[177] *Id.*, line 9, column M (reporting "Annualized Premiums" for NV Energy for 2024).
[178] *Id.*, line 10, column I (reporting "Annualized Premiums" for PSCo for 2020). As discussed herein, the premium number listed for PSCo is actually PSCo's allocation of the corporate-wide ELI policies purchased on PSCo's behalf by its parent company, Xcel Energy.
[179]The WRA Worksheet lists PSCo's 2024 ELI premium as totaling $49,000,000. *Id.*, line 10, column M (reporting "Annualized Premiums" for PSCo for 2024). Another WRA exhibit lists a 2024 premium amount provided by PSCo itself in a Colorado PUC proceeding ($49,386,384). *See* Exhibit WRA__(KB-12). The number provided in Exhibit WRA__(KB-12) is used in Table 2.
[180] Order at 150, *quoting*, WRA Direct at lines 128-32.

Table 3: RMP, NV Energy, PSCo comparative premiums

Utility	State	2020 ELI Premiums	2024-2025 ELI Premiums
NV Energy	Nevada	$2,647,779[181]	$54,343,448[182]
PSCo	Colorado	$5,136,747[183]	$49,386,384[184]
RMP	Utah Allocated	$6,557,841[185]	$11,662,802[186]
PacifiCorp	Total Company	$9,524,782[187]	$26,231,364[188]

The calculation in the Order only authorizes recovery of 2025 RMP ELI premiums at a level approximately $42.6 million below NV Energy's, and approximately $37.3 million below PSCo's.[189] On a total-Company basis, the Order authorizes only $26.3 million to provide ELI coverage for PacifiCorp's six-state service territory. By contrast, the record shows that PSCo's parent, Xcel Energy, pays over $129 million in ELI premiums for its multi-state territory.[190]

Factual Error 3: The WRA's "rate on line" (ROL) calculations relied on in the Order include mathematical errors due to mixing corporate and subsidiary data.[191] For PSCo, WRA claims that "Xcel Energy subsidiary, PSCo, who has not yet incurred losses due to the Marshall Fire, pays $49 million for roughly $500 million in excess liability coverage, yielding an ROL of around 10%."[192] The record shows this calculation is incorrect and the coverage is in fact much

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[181] WRA Workpaper, line 9, column I (reporting "Annualized Premiums" for NV Energy for 2020).
[182] The WRA Worksheet lists PSCo's 2024 ELI premium as totaling $49,000,000. *Id.*, line 9, column M (reporting "Annualized Premiums" for NV Energy for 2024).
[183] WRA Workpaper, Line 10, column I (PSCo ELI premiums as of October 2020 renewal date). As discussed herein, the premium number listed for PSCo is actually PSCo's allocation of the corporate-wide ELI policies purchased on PSCo's behalf by its parent company, Xcel Energy.
[184] *Id.*, line 10, column M (PSCo ELI premiums as of October 2024 renewal date).
[185] *See* Order at 166 n.379.
[186] Order at 166. The approved Test Year ELI Premium in the Order, Utah-allocated, totals $11,662,802.
[187] Phase I Direct Testimony of Joelle Steward at lines 509-510 ("RMP Steward Phase I Direct").
[188] *See* Order at 166 n.379. The Order arrived at a total-Company ELI premium by multiplying $6,557,841 by 400 percent. The product of that multiplication is $26,231,364.
[189] Xcel Energy's allocation of its ELI premiums to its four operating companies (including PSCo) is detailed in Exhibit WRA__(KB-11) at 9.
[190] Exhibit WRA__(KB-12) at 9 (Xcel Energy ELI premiums as of October 2024 renewal date).
[191] *See* Order at 150-152.
[192] WRA Direct at 8.

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lower. The $49 million premium is PSCo's share of the overall ELI premiums paid by the four Xcel Energy operating companies.[193] The Xcel Energy ELI premium totals $129,204,240.[194] The total coverage Xcel obtained for all of its operating companies for that premium amount was approximately $500 million until its 2024 insurance policy renewal.[195]

WRA cites an Xcel news release reporting on Q4 2024 earnings for the $500 million coverage amount. The earnings release, however, makes clear that the $500 million in ELI coverage is for all of Xcel's subsidiaries, not just for PSCo.[196] As part of a discussion of wildfire events impacting PSCo (the Marshall Fire in Colorado) and Southwestern Public Service Company (the Smokehouse Fire in Texas), the Xcel earnings news release cites $500 million as the overall coverage limit for both subsidiaries. Xcel Energy offers further clarity on its insurance coverage in its Annual Report for 2024: "In October 2024, Xcel Energy renewed its excess liability coverage and now has $450 million of total coverage[.] . . . The annual premium for this excess liability insurance is approximately $130 million."[197]

Based on the erroneous premise that PSCo spent $49 million in premiums for $500 million of ELI coverage, WRA argued that PSCo's ROL is approximately 10 percent. If the accurate Xcel premium of approximately $130 million is substituted in the ROL calculation, along with the current Xcel coverage level of $450 million, the ROL nearly triples, going from the 9.8 percent

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[193] Testimony from a PSCo witness in a Colorado proceeding (entered in the record as Exhibit WRA__(KB-11)), makes clear that the $49 million premium amount is only PSCo's allocation of Xcel's corporate-wide ELI premium.
[194] Exhibit WRA__(KB-12) (comparison of ELI premiums paid by Xcel and PSCo included in a PSCo Colorado PUC filing).
[195] WRA Boothman Phase III Workpaper at line 22.
[196] *See* Phase III Direct Testimony of Karl G. Boothman at 8 n.11 ("WRA Direct") *citing*: Xcel Energy, *2024 Year End Earnings Report* (Feb. 6, 2025), *available at*: https://s202.q4cdn.com/586283047/files/doc_financials/2024/q4/Xcel-Earnings-Release-Q4-2024-As-Filed.pdf (last visited May 25, 2025) ("Xcel 2024 Year End Earnings Report").
[197] Xcel Energy 2024 Form 10-K Annual Report at 26 (Feb. 27, 2025), *available at* https://d18rn0p25nwr6d.cloudfront.net/CIK-0000072903/e2853810-9fe1-4df5-89d1-e14f11e5c841.pdf (last visited May 25, 2025).

ROL calculated by WRA to a 28.7 percent ROL using corrected data.[198] Notably, PSCo itself reported to the Colorado Public Utilities Commission ("Colorado PUC") its findings that the typical ROL for Western utilities with "Wildfire Exposure" that experienced losses was 68 percent in 2024.[199]

WRA's erroneous use of the PSCo allocation of Xcel's total ELI premiums also distorts the chart WRA prepared that is duplicated in the Order[200] and relied upon to contrast premium increases for PSCo and the Company. If Xcel's premium of approximately $130 million is used (which is mathematically accurate since the chart uses PacifiCorp's corporate-wide premium amount), the contrast between the Companies' premium increases looks substantially smaller. Figure 1 adjusts the WRA graphic to incorporate Xcel Energy's ELI premiums rather than the premium allocation for only PSCo.

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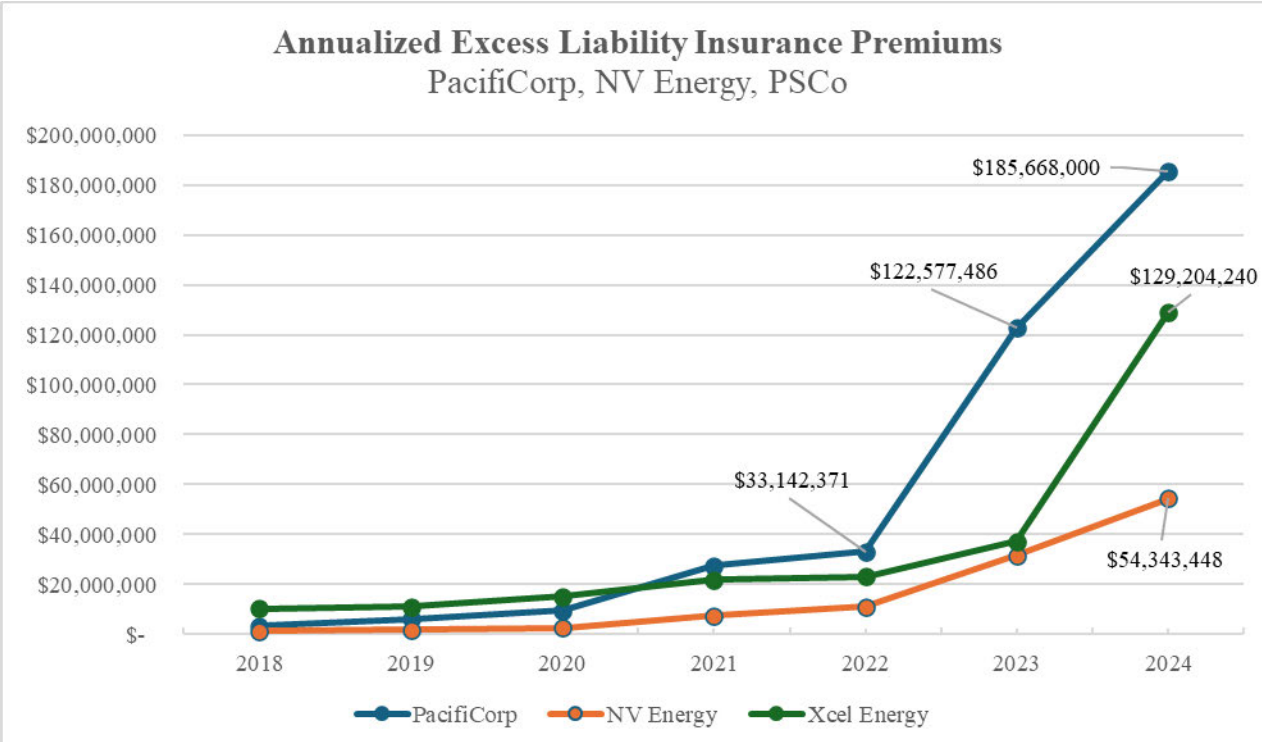
198 This calculation involves adjusting the WRA Workpaper by: (1) substituting $129,204,240 at line 10, column M, and (2) substituting $450,000,000 at line 22, column M. With those inputs, the spreadsheet calculates the PSCo ROL at line 34 to be 28.7 percent.
199 *See* Exhibit WRA__(KB-11)at 13.
200 Order at 152.

Figure 1: "WRA Annualized Premium" chart with adjusted Excel Energy Premiums



Factual Error 4: The calculations relied on in the Order regarding NV Energy's ROL are incomplete and thus also incorrect. WRA relies on an NV Energy filing made in January 2025, at the Public Utilities Commission of Nevada (Nevada PUC) to derive NV Energy's premium and coverage amounts.[201] The NV Energy filing explicitly states that the Nevada utility is unable to obtain sufficient commercial insurance to adequately insure its wildfire risks. In its 2025 filing at the NV PSC relied on by WRA, NV Energy's Chief Executive Officer testified that the $405,000,000 in ELI coverage it has obtained from commercial insurers is insufficient to provide

[201] *See* WRA Direct at lines 116-118 & n.10. WRA cites: "Prepared Direct Testimony of Mariya V. Coleman for Sierra Pacific Power Company d/b/a as NV Energy, Docket No. 25-01019, page 94 of PDF, page 4 of Coleman's supporting testimony (filed January 2, 2025), *available at*, DOCKETS - 25-01019 – ORIGINAL FILING - 1/2/2025 – AGN - UEL - SPP. [hereinafter Coleman Direct Testimony for NV Energy]." References in the Company's brief to the NV Energy, January 2, 2025, filing cited by WRA will reference the Nevada PUC docket number, the name of the witness whose testimony is cited, and the page numbering convention adopted by WRA.

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adequate coverage of NV Energy's wildfire liability risk.[202] NV Energy also testified that it has not been able to obtain the additional insurance coverage it believes it needs "through traditional commercial insurance products at any price, let alone a reasonable price."[203] The unavailability of additional ELI coverage is the basis for the January 2025 filing that requests the Nevada PUC allow NV Energy to begin recovering in customer rates sufficient revenue to fund a $500 million self-insurance policy to be used *in addition to* the commercial ELI policies it has in place.[204]

NV Energy makes clear that it does not consider the amount of coverage it can obtain from commercial ELI markets adequate to prudently manage its wildfire liability risks. The ROL figure for NV Energy is thus based on both coverage and premium amounts that NV Energy has testified are insufficient to insure its corporate risks. Moreover, the "modest increase"[205] in premiums paid by NV Energy, as the Order characterizes it, is at odds with NV Energy's testimony in the Nevada PUC proceeding that they are "ultimately spending 30-40 times as much in 2023-2025 than they did in 2018 for less commercial coverage."[206]

Factual Error 5: The Order relies on misleading comparisons of the Company's premium increases to those of other utilities. The comparisons are calculated in ways that are misleading, and that demonstrate the logical and mathematical hazards of basing ELI premium recovery amounts solely on high-level percentage-based comparisons. Notably, no witness contended that insurers set real-world premiums simply by comparing one insured company's premiums to

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[202] Prepared Direct Testimony of Douglas A. Cannon, CEO of NV Energy, Docket No. 25-01019, at 34-35 of PDF, pages 10-11 of Cannon testimony.
[203] *Id.* at page 36 of PDF, page 12 of Cannon testimony.
[204] *Id.* at page 35 of PDF, page 11 of Cannon testimony: "In this application, [NV Energy companies] ask the Commission to approve the creation of a $500 million self-insurance policy to accomplish the objective of increasing the Companies' insurance limits by $500 million over the commercial insurance currently held by the Companies."
[205] Order at 151.
[206] Prepared Direct Testimony of Mariya V. Coleman, Vice-President of Corporate Insurance and Claims for Berkshire Hathaway Energy Company, Docket No. 25-01019, at page 99 of PDF, page 9 of Coleman testimony.

another. As Company witness Ms. Coleman testified: "I am aware of no analogy in the insurance business to a determination that a reasonable ELI premium for one insured company can be ascertained by simply applying a multiple to another company's premium amounts."[207]

Yet DPU relied on such comparisons when it recommended that "the PSC limit RMP's increase to between 100 and 400 percent of the amount currently in base rates from the 2020 GRC."[208] The Commission noted that "DPU's comparative analysis used the same utilities that RMP regards as reference points, including three large California utilities: PG&E, [San Diego Gas & Electric ("SDG&E)"], and [Southern California Edison Company ("SCE")]."[209]

It is certainly correct that the testimony submitted by Company witness Mr. Graves identified the California utilities mentioned as examples of extraordinary increases in ELI premiums attributable to the increase in the incidence of wildfire liability in the last decade. However, the Company's testimony never suggested that the Commission (or any state commission) should set rates solely based on comparisons with rates charged by other utilities. That is the purpose, however, of DPU's review of other utilities' ELI premiums:

> The data [referenced by RMP witness Graves] begins in the 2015/16 year (for Pacific Gas and Electric Company "PG&E") through the 2022/23 year. PG&E experienced insurance premium growth greater than 1,600% for the entire period from 2015/16 to 2022/23 (.046 per 1 dollar unit to .793 per 1 dollar unit). Southern California Edison Company experienced insurance premium growth of 78.6% for the entire period from 2018/19 to 2022/23. San Diego Gas and Electric Company experienced growth of 176.3% for the entire period from 2016/17 to 2022/23.[210]

DPU concluded that a "400% growth rate to the prior GRC ELI cost" represents "a growth rate greater than all the entities referenced by RMP witness Graves except for PG&E."[211]

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[207] Phase III Rebuttal Testimony of Mariya V. Coleman at lines 56-59 ("Phase III RMP Coleman Rebuttal").
[208] Order at 159.
[209] *Id.* at 159 n.365 (citing Phase III DPU Einfeldt Direct at lines 179-92).
[210] Phase III DPU Einfeldt Direct at lines 179-92.
[211] *Id.* at lines 208-11.

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But DPU leaves out two crucial data points that undermine its conclusion. First, ELI premiums for California utilities were already at unprecedentedly high levels years before the extraordinary increases for other Western utilities began. As Company witness Ms. Coleman testified at hearing, the California utilities started the comparison periods with much higher premium amounts than any of their peers in the Western states.[212] This high starting point distorts comparisons to RMP, which started the applicable comparison periods with significantly lower ELI premiums. This problem with mismatched percentages is depicted in Table 4.

Table 4: California utilities and PacifiCorp ELI premiums – 2020-2023[213]

Utility	State	2020 ELI Premiums	2023 ELI Premiums	Percentage Change 2020-2023
SCE	CA	$400,000,000[214]	$357,000,000[215]	(10.75%)
SDG&E	CA	$183,000,000[216]	$221,000,000[217]	21%%
PG&E	CA	$158,500,000[218]	$745,600,000[219]	370%
PacifiCorp	CA, ID, OR, UT, WA, WY	$9,524,782[220]	$122,577,486[221]	1,187%

Table 4 shows the premium amounts SCE, SDG&E and PG&E were paying for California-only ELI coverage in 2020 and 2023. This comparison highlights the distortions caused by comparing data from varying time periods, as DPU's testimony does. In 2020, California utilities were already paying hundreds of millions of dollars more to insure their single-state territories than PacifiCorp paid to insure its six states. The premium levels of all California utilities were, as

[212] March 20 Hr'g Tr. at 115:11-116:6 (Coleman).
[213] Table 4 uses 2023 as a reference point because the data in the record does not include 2024 premium amounts for all of the California utilities.
[214] WRA Phase III Workpaper, line 6, column I (SCE "Annualized Premium" for 2020).
[215] *Id.*, line 6, column L (SCE "Annualized Premium" for 2023).
[216] *Id.*, line 5, column I (SDG&E "Annualized Premium" for 2020).
[217] *Id.*, line 5, column L (SDG&E "Annualized Premium" for 2023).
[218] *Id.*, line 7, column I (PG&E "Annualized Premium" for 2020).
[219] *Id.*, line 7, column L (PG&E "Annualized Premium" for 2023).
[220] RMP Steward Phase I Direct at lines 509-510.
[221] *Id.*

dollar amounts, substantially higher than the Company's, even before its extraordinary premium increase in 2023. California utilities saw their major increases in premium levels earlier in time,[222] which distorts percentage comparisons between 2020 and 2023 in an attempt to align the Company's ELI premium increases from 2023 to date with those of other utilities.

Figure 2 depicts the impact of these facts in a revised version of the "WRA Annualized Premium" chart discussed above. If the 2018-2024 premiums for the California investor-owned utilities ("IOUs") that WRA included in the analysis in the WRA Workpaper are added to the WRA Annualized Premium chart that was reproduced in the Order, the fact that California utilities were already paying extraordinary ELI premiums long before the Company or other utility peers faced such increases is easily visible, as well as the way premium increases have leveled smoothed out (but remain at high levels) in recent years for SCE and SDG&E.[223]

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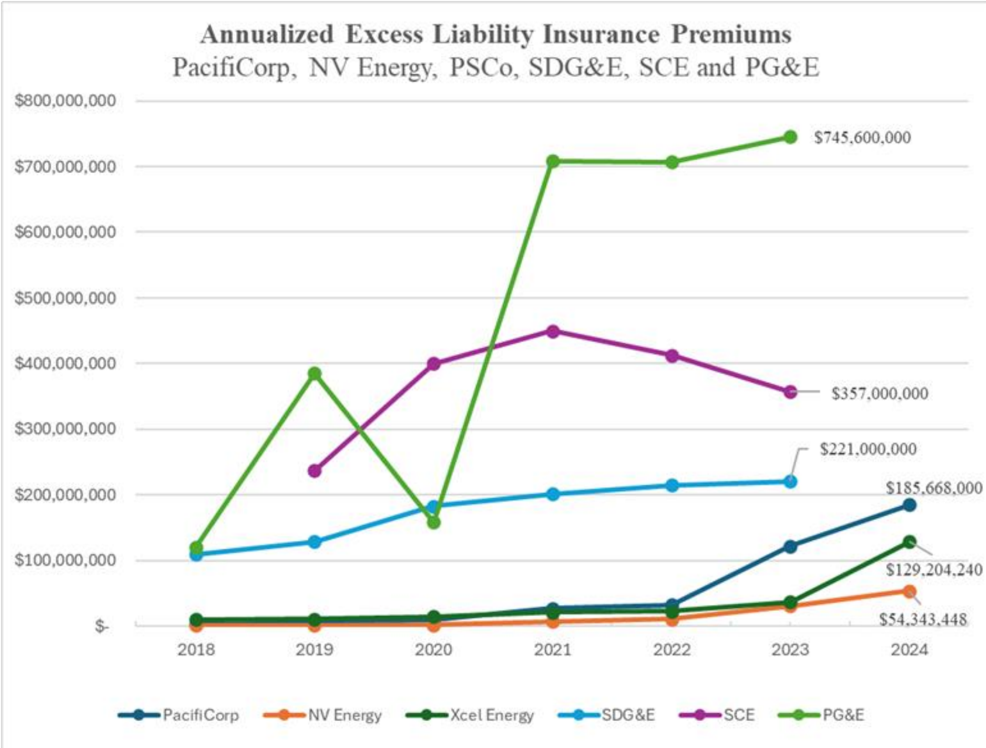
[222] PG&E, for example, paid $42,900,000 in ELI premiums as early as 2016, and experienced an 898 percent increase to $385,200,000 by 2019. *See* WRA Workpaper, comparing PG&E 2016 premiums at line 7, column E, to 2019 premiums at line 7, column H.

[223] Figure 3 adds the California utility premium data derived from the WRA Worksheet and also includes the Xcel Energy premium adjustment depicted in Figure 2 for the PSCo line. The California utilities' premium data used in Figure 3 appear in the WRA Workpaper at lines 5-7, columns G-M. The WRA Workpaper does not include 2018 premium data for SCE or 2024 premium data for any of the California IOUs.

Figure 2: "WRA Annualized Premium" chart including California utilities



The lower raw percentage increases DPU calculated also ignore developments in California in recent years that have impacted ELI premium levels. For example, since 2019, the California IOUs cited in DPU's comparisons (SCE, SDG&E and PG&E) have paid a total of $9 billion into the California Wildfire Fund, which provides "$21 billion of claim-paying coverage to California IOUs in the event of wildfire damages exceeding $1 billion (assumed to approximate the level of commercial insurance available to each of the California IOUs)."[224] In addition, the California Public Utilities Commission ("California PUC") recently began authorizing recovery in customer rates for most California IOUs "of very substantial wildfire self-insurance costs over multi-year periods."[225] A dedicated source of California PUC-approved funding for self-insurance, combined with the IOU investments in the California Fire Fund, appear to have moderated the level of ELI

[224] Phase I RMP Graves Direct at lines 718-722.
[225] *Id.* at lines 535-538.

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premium increases for commercial insurance policies (as depicted in the premium percentage increases shown in Table 4)—but those costs and funding sources should be considered in examining (for purposes of comparisons with the Company) what the California IOUs must pay to insure against liability claims.

In addition, DPU's premium comparisons for Avista and Idaho Power do not include information on coverage limits, ROL, or other information is needed to make the raw percentage numbers meaningful. DPU's testimony notes that: "Avista experienced growth of 100% from 2020/21 to 2022/23, and Idaho Power experienced growth of 100% for the entire period from 2018/19 to 2022/23."[226] Nothing in the record, however, indicates what coverage levels these utilities obtained for their premiums, whether the utilities obtained coverage with reduced or increased coverage limits compared to previously obtained policies, or the nature of the claims history each utility had with its insurers. Each of these factors is essential to understanding the value utilities obtain when they purchase ELI policies. DPU's references to Avista's and Idaho Power's premium increases offer none of that essential context[227] and thus do not provide a sufficient evidentiary basis for the reliance the Order places on them.

The actual 400 percent multiplier applied to calculate the Company's authorized ELI premiums has no basis in the record other than as part of DPU's recommendation. There is not a comparable Western utility whose ELI premium increases match or provide precedent for the 400 percent figure chosen in the Order. As discussed above, the comparative calculations that underlie the Commission's decision to use the 400 percent multiplier are replete with mathematical errors, ignore evidence that undermines them as meaningful comparisons to the Company's ELI

[226] Phase III DPU Einfeldt Direct, at lines 190-192.
[227] *See* Phase III Rebuttal Testimony of Frank Graves, at lines 116-154.

premiums, and create arbitrary outcomes that contradict the notion that they are "commensurate" with ELI premiums paid by PSCo and NV Energy.

4. The Order claims to tie the prudence of the Company's ELI premiums to utilities whose ELI loss histories do not include wildfire events. This method of establishing the recoverability of ELI premiums is contrary to the record evidence and arbitrary as applied to the Company.

The Order calculated the Company's recoverable ELI premiums by multiplying 2020 GRC approved premiums by "400 percent to reflect an increase commensurate with peer utilities," namely PSCo and NV Energy, "*that have not experienced catastrophic wildfire events*."[228] The Order's determination that the "peer utilities" category for purposes of setting RMP's recoverable ELI premiums should include utilities that "have not experienced catastrophic wildfire events" is not supported by record evidence, contradicts key information in the record, and arbitrarily limits the Company's recovery of ELI premiums.

a. The Order fails to recognize that PSCo has experienced a catastrophic wildfire event.

Contrary to statements in the Order, PSCo *has experienced* a catastrophic wildfire event, the Marshall Fire, which occurred in December 2021.[229] PSCo's parent corporation, Xcel Energy, described the Marshall Fire and pending litigation against PSCo as follows in February 2025 (in the earnings report used to develop WRA's Phase III testimony):

> In December 2021, a wildfire ignited in Boulder County, Colorado (Marshall Fire), which burned over 6,000 acres and destroyed or damaged over 1,000 structures. . . . According to an October 2022 statement from the Colorado Insurance Commissioner, the Marshall Fire is estimated to have caused more than $2 billion in property losses. . . . In September 2023, the Boulder County District Court Judge consolidated the pending lawsuits into a single action for pretrial purposes and has

[228] Order at 166 n.379 (emphasis supplied). *See* also, Order at 166 ("[T]he PSC finds allowing RMP to recover from Utah ratepayers the amount it recovered for ELI Premiums in the 2020 GRC, adjusted for premium increases commensurate with its peer utilities . . . that have not experienced catastrophic wildfire losses, to be just and reasonable.").
[229] *See* WRA Phase III Direct, at lines 75-77 (referencing "pending litigation concerning PSCo's involvement in the Marshall Fire, which destroyed over 1,000 structures near Boulder, [Colorado].").

> subsequently consolidated additional lawsuits that have been filed. At the case management conference in February 2024, a trial date was set for September 2025.[230]

Xcel added that "[Xcel] and PSCo are unable to estimate the amount or range of possible losses in connection with the Marshall Fire," but if the companies were found liable, damage amounts "could exceed our insurance coverage of approximately $500 million and have a material adverse effect on our financial condition."[231]

The record thus contradicts the Order's contention that PSCo has not experienced a wildfire event. Moreover, Xcel's representations regarding the Marshall Fire make clear that Xcel/PSCo have numerous claims still pending that may become part of its insurance loss history in the future. PSCo has had a wildfire event, has experienced premium increases of approximately 860 percent since 2020 (*see* Table 2 above), and the company's insurance loss history from the Marshall Fire remains uncertain as litigation over the fire proceeds. Based on these factual circumstances, it is difficult to understand the Order's conclusion that PSCo's experience supports the 400 percent ELI premium increase for RMP that purportedly reflects "an increase commensurate with peer utilities that have not experienced catastrophic wildfire events."[232]

b. The Order is inconsistent with the record regarding the impact of loss history on future ELI premiums.

The Order's conclusions are inconsistent with the record evidence demonstrating that an insured company's loss history "is fundamental to how an insurer views the risk involved in offering a company insurance coverage."[233] The Order compares the Company's recent ELI

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[230] Xcel 2024 Year End Earnings Report, at 16.
[231] *Id.* at 75-76. The use of PSCo as a comparable utility is particularly inapt since both PacifiCorp and PSCo experienced catastrophic wildfires, and both have contended with liability claims based on those fires. PSCo does not, however, yet know the amount of losses it will face from the Marshall Fire – losses that when added to its loss history will likely increase its future ELI premiums even higher – while the Company has already had to purchase ELI insurance after using its insurance to cover claims from the 2020 Labor Day fires.
[232] Order at 166 n.379.
[233] Phase III Direct Testimony of Mariya V. Coleman at lines 170-171 ("Phase III RMP Coleman Direct").

premium increases to those of "peer utilities" using blinders that eliminate one of the most important drivers of premium increases. ELI premium rates offered to a company take its loss history into account, and the Order's methodology for establishing RMP's recoverable premiums eliminates consideration of premium increases experienced by Western utilities that have experienced wildfire events and paid associated liability claims that were covered by their ELI policies.

There is no dispute in the record that loss history is a key component of how insurers determine ELI premiums, and that insurers will raise premiums or impose other charges to recover paid losses on their policies. For example, Company witness Ms. Coleman testified:

> If an insured party makes claims on its insurance policy, it increases the insurer's financial exposure, which, in turn, impacts the rates at which the insurer is willing to offer coverage. The basic calculation excess liability insurers make in setting rates for large policies like those required by the Company is similar to setting rates for smaller policies like those offered for consumer automobile insurance: the number of claims on a policy increases the insurance company's financial exposure, and the insurance company will demand higher premiums to compensate for the increased risk.[234]

In addition to Ms. Coleman, the DPU witnesses in the proceeding who have expertise in the insurance industry echoed the conclusion that insurers will increase premiums, or take other measures, to recover the costs they incurred covering a utility's large claims. DPU witness Mr. Gleba noted, with specific reference to large losses involving insured utilities:

> [F]or large insureds, like regional utilities, which have no direct comparable and near identical peer in the insurer's portfolio, there is some sense that the individual insured should fund by way of their subsequent year premiums and possibly a change in program structure such as increased retentions/deductibles, some or all of any large and unique loss over the lifetime that they are a customer of the insurer, through an informal "payback" mechanism.[235]

[234] Phase III RMP Coleman Direct, at lines 171-78.
[235] Phase III Direct Testimony of John Gleba, at lines 388-394 ("Phase III DPU Gleba Direct").

Similarly, DPU witness Mr. Kelly referenced information regarding insurer actions to address premium costs after it has covered large utility wildfire claims:

> [redacted][236]

Loss history is not the only factor in determining ELI premium increases, and the Company has not claimed it is.[237] Nevertheless, the record demonstrates that past claims paid on ELI policies influence future premiums that insurers are willing to offer for policy renewals. If a company has experienced a significant loss and has called upon its ELI insurers to cover it, the ELI insurers will only offer increased premiums (or, as Mr. Gleba's testimony described, other charges or changes in policies) that result in more expensive ELI coverage when policies are renewed. In those circumstances, the alternatives available to the insured company are different from those available to companies who have not made claims against their insurance policies to a similar extent.

When the Order bases the Company's authorized ELI premium amounts on those of utilities that have not experienced wildfire events (with their associated claims on ELI policies), the Order requires the Company's recovery of ELI premiums be based on utilities that are fundamentally dissimilar to it in a way that matters. If ELI premiums offered to companies that have not experienced a wildfire event provide a ceiling for the Company's recoverable premiums,

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[236] Phase III Direct Testimony of Peter J. Kelly Direct, at lines 440-446 ("Phase III DPU Kelly Direct") (quoted text designated Confidential). DPU witness Einfeldt made a similar point to those expressed by DPU's expert witnesses: "[I]nsurers' costs paid for losses related to the Company's recent wildfires, and the insurers' expectations for potential losses will drive up premiums." Phase III DPU Einfeldt Direct at lines 202-04.

[237] *See* March 20 Hr'g Tr. at 109:20-24 (Coleman) ("I think we've said that explicitly several times that loss history is a contributing factor, and there are significant other risk factors and operational statistics that insurers consider when underwriting a specific industry.")

then the Company is being held to account for failing to obtain policies with premium levels that were not available to it in the insurance market.

One of the fundamental premises of prudence analysis in Utah calls on the Commission to "determine whether a reasonable utility, knowing what the utility knew or reasonably should have known at the time of the action, would reasonably have incurred all or some portion of the expense, in taking the same or some other prudent action."[238] By defining the reasonableness of the Company's ELI premiums with reference to utilities that have much different loss histories, the Order holds RMP to a standard it could not have met when it purchased ELI policies in 2023 and 2024. The testimony of the witnesses with insurance industry expertise (Ms. Coleman, Mr. Gleba, and Mr. Kelly) makes clear that policies available to utilities without wildfire-related loss histories are not available on similar financial terms to utilities who have used ELI policies to pay for significant wildfire liabilities. As Company witness Coleman testified, "It is hard to imagine an insurer seriously proposing to base the Company's ELI premiums on the loss histories of different utilities—much less two utilities [PSCo and NV Energy] that have such dramatically different loss histories than the Company."[239] The Order disallows most of what the Company paid for ELI coverage because it did not buy policies with lower premiums that were not available to it.[240] This is an unreasonable and arbitrary outcome that the Commission should reconsider.

5. <u>The Order ignores record evidence about the nature of the forward-looking wildfire risks that lead to increased ELI premiums.</u>

The Order concludes that "[i]nsurers are plainly identifying risk associated with insuring RMP that the insurers do not identify when insuring NV Energy, PSCo, and others that have not

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[238] Utah Code Ann. § 54-4-4(a)(iii).
[239] Phase III RMP Coleman Rebuttal at lines 720-22.
[240] Another section of the Company's motion refutes the Order's conclusions that the Company did not exercise due diligence in purchasing the ELI polices that were available to it in 2023 and 2024 (and serve as the basis for the Test Year).

experienced catastrophic wildfire losses."[241] But the record shows that NV Energy and PSCo were also not able to obtain ELI policies for their single-state territories with premiums anywhere near as low as the amount the Order authorizes for the Company. When utilities "*that have not experienced catastrophic wildfire events*,"[242] according to the Order, must spend between approximately $49 million (PSCo) and $54 million (NV Energy) to obtain ELI policies, it is apparent there is something missing in the Order's analysis of the risks driving ELI premium increases.

The circumstances facing PSCo, NV Energy, and the Company are in large measure related to insurers' perceptions of the *future risk* facing utilities operating in Western states. Nevertheless, the Order disregards the record evidence documenting forward-looking risks of wildfire. This is a critical omission, since the primary function of insurance policies is, after all, to mitigate costs when future risks come to fruition.

The Order fails to recognize undisputed evidence demonstrating that insurers consider Utah (like other Western states) to have risks of wildfire independent of whether the state has experienced a recent wildfire. The Company emphasized this point in its direct testimony in Phase III:

> Beginning around the time of the 2007 wildfires in California, it became clear to utility insurers that wildfire was becoming a more frequent and widespread risk. . . Utility insurers' policy offerings increasingly focused on wildfire risk exposure. For example, policy limits applicable to wildfire increased to reflect growing liability risks. By 2020, AEGIS and other utility insurers began to charge a separate excess liability premium for wildfire coverage. At that point, separate wildfire premiums were originally applied to utilities that had faced the highest historical risk (e.g., the California utilities exposed to several devastating fires through the 2000s and 2010s). *In the past several years, however, the 2020 fires that impacted the Company, the Maui fire in 2023, and major fires in Colorado, Texas, and Canada,*

[241] Order at 161.
[242] *Id.* at 166 n.379 (emphasis supplied).

have accentuated the fact that wildfire risk is no longer limited to the geographic locations where it had historically been an issue.[243]

The record documents the risk of future wildfires in Utah, along with other Western states in the Company's service territory:

- Data compiled by the U.S. Department of Agriculture and U.S. Forest Service states that "Utah has a very high risk of wildfire—higher than 90 [percent] of [the] states in the US," and Salt Lake County, Utah, has a higher wildfire risk "than 96 [percent] of counties" in the U.S.[244]

- Verisk's "Wildfire Risk Report 2024," a document prepared for an insurance industry audience, reports on wildfire risk in thirteen U.S. states.[245] Verisk considers each state's risk based on eight standard indicia. Review of the document during cross-examination at hearing made clear that Utah is not only a state where Verisk perceives significant wildfire risk, but that Utah ranks higher than many of the other states on many of the wildfire risk indicia examined by Verisk.[246]

- Company witness Ms. Coleman reported that "Insurers have specifically added charges in order to insure wildfire risks in the following Western States: Alaska, Arizona, Colorado, Hawaii, Idaho, Montana, New Mexico, Nevada, Texas, Utah, Washington, Wyoming."[247]

- DPU witness Mr. Gleba's testimony identified several "liability exposure measures that could be used for allocating insurance premium by operating state within PacifiCorp's jurisdiction."[248] These measures, while not all strictly tied to wildfire exposure, include High Fire Risk Area transmission and distribution line miles, numbers of poles, number of customers, and other factors that influence the ignition or spread of wildfire. When reviewing his testimony on cross-examination, Mr. Gleba agreed that of the six PacifiCorp states, Utah ranks either number one, two, or three on all twelve of the liability exposure measures he identified.[249]

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[243] Phase III RMP Coleman Direct, at lines 285-301 (emphasis supplied).
[244] *See* RMP Cross Exhibit 13, Data from U.S. Department of Agriculture and U.S. Forest Service website "wildfire.org." *See also*, March 21 Hr'g Tr. at 225:22-226:14 (Einfeldt) (discussion of Exhibit 13).
[245] *See* RMP Cross Exhibit 12, Verisk Wildfire Risk Report 2024 at 14. The introductory section of the Verisk report states: "Wildfires are intensifying, and the threat to the built environment is growing. This collection of state-specific reports provides insurers, policymakers, and community leaders with the critical data and insights needed to understand, mitigate, and manage the growing threat of wildfire." *Id.* at 3.
[246] March 21 Hr'g Tr. 189:7-191:22. (Gleba) (agreeing that nothing in the 2024 Verisk report "says Utah has a relatively low risk among the 13 western states").
[247] Phase III RMP Coleman Rebuttal, at lines 225-227.
[248] Phase III DPU Gleba Direct, at lines 635-638 (Table 4.5) (table is marked confidential).
[249] March 21 Hr'g Tr. at 197:24-199:16.

The insurance industry's focus on estimating future risks and incorporating them in rates was emphasized in DPU witness Mr. Gleba's direct testimony, where he quotes the Casualty Actuarial Society's "Statement of Principles on Ratemaking":

> [A]n insurance rate is reasonable and not excessive, inadequate, or unfairly discriminatory if it is an actuarially sound estimate of *the expected value of all future costs* associated with an individual risk transfer. . . . A rate is an *estimate of the expected value of future costs*. . . . Historical premium, exposure, loss and expense experience is usually the starting point of ratemaking. This experience is *relevant if it provides a basis for developing a reasonable indication of the future*.[250]

By contrast, the Order assessed the reasonableness of Test Year, forward-looking ELI premiums only by what has happened in the past—particularly the fact that major wildfires occurred in other states in the Company's service territory since ELI rates were approved in 2020, but not in Utah. This approach disregards undisputed evidence that insurers do not price policies looking only in the rear-view mirror, and that insurers do not ignore future wildfire risk in Utah or other states when they price ELI policy renewals.

The need to protect against known future risks supports the Company's decisions to purchase ELI policies even as the ROL (amount of coverage for dollar of premium paid) increased. The Order ignored future risk of catastrophic wildfire when it held that purchasing ELI for "50 cents for every dollar of coverage" is unreasonable.[251] The central problem is that neither the Company, nor any utility, can accurately predict the occurrence of a catastrophic wildfire in its service territory.[252] And the consequences of guessing wrong are devastating. If a utility chooses to reduce ELI coverage in a year when a wildfire causes extreme damage to its service territory,

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[250] Phase III DPU Gleba Direct, at line 1181-1217 (emphasis supplied and omitted).
[251] Order at 163 ("[U]nless the utility reasonably expects to incur insured losses equal to the policy limit at least every two years, the utility will pay more in premiums than it can possibly recover on the coverage.")
[252] *See* Phase I RMP Graves Direct at lines 390-94. (Wildfire "challenges are a moving target, and factors outside the control of the utility will significantly determine the extent of the outcome of consequences and damages of wildfires. . . . [I]t has also made modeling of fire risk quite difficult and inconsistent with recently observed disasters.").

the utility could face catastrophic financial outcomes that could have been substantially mitigated by obtaining adequate insurance coverage. Moreover, PSCo's testimony before the Colorado PUC reports that the ROL for Western states utilities exposed to wildfire damages that experienced loss was 68% in 2024.[253] The Company's ROL was not out of line with similarly situated utilities facing wildfire risks.

Past events were the exclusive focus of the 400 percent multiplier recommendation adopted in the Order. At hearing, DPU witness Mr. Einfeldt confirmed his analysis did not look at future risk, and admitted that insurers' policy renewal analyses do include such risks:

> Q.: . . . So I understand you looked back at wildfire events in the past. Did you—did you do any assessment of current or future looking likelihood of wildfire in Utah?
>
> A. [Mr. Einfeldt]: No, I did not.[254]
>
> …
>
> Q.: Now, when insurers decide on renewing policies, aren't they looking at—sure, they're looking at the past, but they're looking at the present and the future as well, aren't they?
>
> A. [Mr. Einfeldt]: Based on prior testimony, that sounds like what—what is the case.
>
> Q. Okay. So an analysis that only looks at the past might be missing something. Is that fair to say?
>
> A [Mr. Eindfeldt]: Oh, yes. Yes.[255]

The Order's adoption of the 400 percent multiplier is inconsistent with undisputed record evidence that real-world insurers consider forward-looking risk factors, for Utah and for all other states where their policies will be in effect. The Order's conclusions, and the parties' recommendations underlying it, left out a key determinant of whether the Company's ELI premiums are reasonable.

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[253] *See* Exhibit WRA__(KB-11) at 13.
[254] March 21 Hr'g Tr. at 225:8-12 (Einfeldt).
[255] *Id*. at 226:6-14 (Einfeldt).

Those conclusions are outcome-determinative, but contrary to the record. The Commission should reconsider them.

6. The Order's conclusion that RMP failed to actively procure lower ELI premiums or use self-insurance is based on insufficient or non-existent record evidence.

The Order did not substantively challenge the policy limits or need for the ELI coverage the Company procured in its 2023 or 2024 policy years. Rather, the Order imposed a draconian prudence disallowance based in large measure on the Company's due diligence in examining alternatives to the polices that it procured. Without making any findings about the prudence of the amount of ELI coverage the Company purchased, the Order questioned whether the Company obtained sufficient value for its insurance purchases. The Order claimed, without support, that "other utilities facing such adverse terms reasonably pursue self-insurance because it offers far better value."[256] In addition, the Order suggested that the Company would have made a more economic decision by shifting to self-insurance in 2023 or earlier. None of the Order's conclusions on these issues are supported by the record; rather, they are at odds with the evidence presented in testimony and at hearing.

a. The Company "reasonably and responsibly" evaluated its insurance procurement decisions.

The Order held that "a reasonable utility, experiencing premium increases of the magnitude RMP has since 2020, would reasonably and responsibly evaluate its insurance procurement decisions."[257] The overwhelming weight of the record evidence demonstrates that the Company did that.

- Company witness Ms. Coleman presented undisputed testimony that the "Company works with experienced insurance brokers for months as its ELI renewal dates approach. The Company, through [Berkshire Hathaway Energy's ("BHE")] Corporate Insurance

[256] Order at 163.
[257] *Id.* at 162.

department, meets and presents to all of its panel insurers and prospects and answers numerous questions from insurers leading up to the renewal.”[258] Ms. Coleman added at hearing: “I’ve been involved in procuring the Company’s excess liability insurance policies for more than a decade and . . . I can confirm the Company strives for the lowest premiums possible at acceptable coverage levels.”[259]

- Several pages of DPU witness Mr. Kelly’s direct testimony detail the extensive interactions between the Company’s BHE insurance procurement team, its brokers, and insurance companies during the 2024 policy period ELI renewal.[260] Mr. Kelly’s narrative was drawn from information provided by the Company in response to intervenor discovery requests. Mr. Kelly reports on email exchanges in which the Company’s brokers indicated that in 2024 [redacted]”[261] At no point in this discussion does Mr. Kelly fault the Company for not diligently seeking the best possible terms in a “hard market.”

- A part of BHE’s “August 2025 commercial insurance renewal, the Company negotiated an 18-month policy term, which, in a time of increasing premiums and decreasing coverage, provides more certainty than the annual policies insurers traditionally offer.”[262]

Despite the evidence of the Company’s diligent efforts in its insurance procurement process, the Order focused on a single response to a WRA discovery request as the basis for holding the Company’s procurement actions were not reasonable.[263] However, Company witness Ms. Coleman testified that the types of information WRA asked for would be “virtually useless” to address the actual issues the Company faces in negotiating with insurers.[264] The Company provided detailed descriptions [redacted] about the types of data and information an insurer expects to receive from insured utilities.[265] [redacted]”[266] [redacted]

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[258] Phase III RMP Coleman Rebuttal, at lines 749-755.
[259] March 20 Hr’g Tr. at 79:15-19 (Coleman).
[260] Phase III DPU Kelly Direct at lines 637-78 and 713-63 (all marked confidential).
[261] *Id.* at lines 643-647.
[262] Phase III RMP Coleman Rebuttal at lines 752-55.
[263] *See* Order at 162.
[264] Phase III RMP Coleman Rebuttal at line 747.
[265] *See* Phase III RMP Coleman Direct, Exhibit MVC-1.
[266] *Id.* at 1.

[redacted][267] The Company must provide such detailed information to its underwriters, and this is the actual information insurers rely upon to develop policy renewals. Neither WRA's witness, nor WRA as an organization, has any discernible experience underwriting utility insurance policies or preparing the documents that insurers require to develop ELI policies. It is unreasonable to conclude the Company's insurance procurement practices are lacking based on discovery responses to questions that are uninformed by any actual experience in the insurance industry.

Similarly, WRA's claims that the Company's wildfire mitigation plans ("WMP") were viewed in a detrimental way by insurers is without factual support. The Company's experience interacting with real insurance companies is exactly the opposite. Company witness Ms. Coleman testified, based on over a decade of experience procuring insurance for BHE companies:

> From my own experience, I can confirm that the Company's WMP and other mitigation efforts play an extremely important role from the viewpoint of our insurers. [WRA witness] Mr. Boothman is correct that insurers are increasingly interested in wildfire mitigation measures, and if the Company did not bring a credible program to the table, our coverage options would [be] much more problematic than they are today. The Company's insurers view our wildfire mitigation commitments as a strength, contrary to how WRA seeks to portray them.[268]

Finally, it is notable that WRA applauds NV Energy's efforts to seek reasonable ELI premiums and to petition the Nevada PUC to authorize a large self-insurance program.[269] The people who negotiate NV Energy's ELI coverages are the same BHE insurance professionals who negotiate coverage for PacifiCorp. In fact, when WRA's testimony referenced NV Energy's Nevada PUC filings, it quotes the testimony of Ms. Coleman.[270] It is rather difficult to credit WRA's assertions

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[267] *Id.* at 3.
[268] Phase III RMP Coleman Rebuttal at lines 764-70.
[269] WRA Direct at lines 355-60.
[270] *Id.* at 8 n.10.

that Ms. Coleman and the BHE team perform excellent work for NV Energy, but the same people and organization lack competence when they procure insurance for RMP. It is also telling that such inconsistent critiques come from a witness with no experience in the insurance industry.

b. The Order's findings regarding the Company's consideration of self-insurance are contradicted by the record.

In 2023, when the Company saw unprecedented increases in ELI premiums demanded by its insurers, it spent approximately $122.6 million, total-Company, to obtain liability coverage for approximately $542.5 million.[271] If the Company had chosen to abandon commercial insurance due to the high costs, but wanted to maintain the same level of coverage, the Company would have had to spend $542.5 million on self-insurance in 2023 instead of $122.6 million in premiums. Self-insurance is not a one-for-one replacement for commercial insurance policies unless a company is prepared to self-fund every dollar of coverage it requires. Expanding self-insurance can, however, provide savings when premium costs and increasing ROL make self-insurance a more economic choice than commercial ELI policies. The Order erred in its holdings on both the Company's actions to pursue self-insurance alternatives, and on the actions of other Western utilities.

Contrary to WRA's assertions, the Company began discussions with stakeholders in all of its states about expanding self-insurance in 2023—the same year it was presented with extraordinary ELI premium increases by its insurers.[272] Prior to convening these discussions, the Company retained Brattle Group to evaluate and support proposed regulatory tools aimed to mitigate insurance costs.[273] The stakeholder discussions, which are still ongoing,[274] involve representatives of state commissions, consumer groups, and other interested parties, and are

[271] RMP Steward Phase I Direct at lines 509-10.
[272] *See id.* at lines 588-90. ("To facilitate input, PacifiCorp convened an ongoing series of meetings and workshops with the participants in the Multi-State Process.")
[273] *Id*. at lines 582-83.
[274] The Company held the most recent stakeholder workshop on April 30, 2025.

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conducted on a confidential basis to foster open discussion and encourage negotiation. PacifiCorp has presented information in the stakeholder workshops on the potential costs and benefits of using combinations of commercial policies and self-insurance to manage wildfire liability risks.[275] The Company hoped to obtain consensus among its state stakeholders before presenting a self-insurance proposal for state commission approval. While the workshop process continues, that consensus has not emerged. Nevertheless, the Company has committed to presenting a proposal featuring expanded self-insurance to the Commission in 2025. The Order's assertions that the Company has been insufficiently assertive in moving to increased reliance on self-insurance is belied by the record of its actions on the issue.

The Order's assertion that "other utilities facing such adverse [ELI] terms reasonably pursue self-insurance because it offers far better value"[276] mischaracterizes other utilities' actions, and the timing of those actions. The examples in the record of other utilities pursuing self-insurance include NV Energy and the California IOUs. As noted above, NV Energy's 2025 self-insurance filing at the Nevada PUC requests not a replacement of its commercial ELI policies with "better value" self-insurance, but a request for authorization to fund a self-insurance program in addition to existing commercial ELI policies, because NV Energy can no longer obtain sufficient insurance from commercial markets.[277] Moreover, NV Energy filed its proposal in Nevada in early 2025, and the Company plans to file its proposal with this Commission and in other states this year as well.

The California utilities' self-insurance programs are the result of a multi-year regulatory process that involved several proceedings to establish appropriate insurance levels and payment

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[275] RMP Steward Phase I Direct at lines 633-749.
[276] Order at 163.
[277] Prepared Direct Testimony of Douglas A. Cannon, CEO of NV Energy, Docket No. 25-01019, at 35 of PDF, page 11 of Cannon testimony.

streams to fund self-insurance. In approving PG&E's transition to self-insurance in 2023, the California PUC held:

> Since 2017, wildfire liability insurance paid for third-party claims has risen to the point that self-insurance is likely to achieve sufficient insurance coverage at a lower overall cost to PG&E's customers than commercial insurance. . . . Now that the cost of commercial insurance is up to 80 percent of the coverage it would provide, the [California PUC] finds the Settlement recommending PG&E to use self-insurance for wildfire claims to be a reasonable alternative.[278]

While the California PUC's decision to wait until ROL was at 80 percent to advance self-insurance is certainly debatable, it is clear that PG&E and other California utilities did not immediately flash cut to self-insurance when wildfire liability risk began to accelerate ELI premium increases.

The record demonstrates that the Company has actively pursued self-insurance options and continues to do so, and that its actions on self-insurance are not out of step with other Western utilities facing escalating ELI premiums. The Commission should consider the Order's inaccurate findings on the Company's prudence in its procurement of commercial ELI policies and its consideration of a transition to expanded use of self-insurance.

C. The Commission ROE Determination Is Unsupported, Inconsistent with Prior Commission Orders, and Incorrect.

In the Order, the Commission denied RMP's request for an ROE of 9.65%, which is the same ROE approved in the 2020 GRC, and determined that the ROE should be set at 9.35%. The Commission arrived at this conclusion on the basis of the following conclusions:

- That economic and regulatory conditions have changed in a manner that, according to the Commission, justify a lower ROE;[279]

- None of the Company's ROE modeling was credible because "RMP's estimated growth rate and equity risk premium used in [its] models' analyses are based on projected growth rates that are completely unrealistic and produce unreliable results";[280]

[278] *See* CPUC A.21-06-021, PG&E Decision at 2, 15 (Jan. 17, 2023), cited in Phase I RMP Graves Direct at 27.
[279] Order at 29-30.
[280] Order at 25.

- UTLCG's and OCS's recommended ROE ranges were "credible and persuasive";[281] and

- ROEs approved nationwide over at least the last 20 years, including the ROE determination by this Commission in 2020, have been overstated.[282]

These conclusions are flawed, and the Commission's ROE determination should be reversed, or the Commission should order a rehearing on the appropriate ROE for the Company.

1. <u>Economic and Regulatory Conditions Have Changed in Ways That Increased, Not Decreased, the Cost of Equity.</u>

The Commission concluded in the Order that economic and regulatory conditions have changed since 2020 and justify a lower ROE. However, the Order contains almost no discussion of the changed (worsened) economic conditions since 2020 and adopts a position on regulatory conditions that is unsupported and contrary to the positions of the Company and the OCS.

a. It is undisputed that economic conditions have worsened since 2020.

The Order concedes that economic conditions have changed since 2020, but concludes, without any citation to any factual support, that "[t]he significant economic uncertainty" and related economic issues that were present during the COVID-19 pandemic "have passed."[283] The Commission arrives at this conclusion as if to suggest that economic conditions since 2020 have improved. But that is not the case, and the evidence is undisputed on that point. The Opinion itself notes that, since the pandemic, "interest rates are higher" and "[i]nflation is higher."[284] Further, notably absent from the Order is the fact that the utility cost of equity, both for the Company and industry-wide, has increased, not decreased, since 2020.

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[281] *Id.* at 26
[282] *Id.* 27-28.
[283] Order at 22.
[284] *Id.*

As Ms. Bulkley demonstrated (and it is undisputed), core inflation increased since the last GRC, from 1.41 percent in January 2021 to a high of 6.64 percent in September 2022, to a rate that still exceeds the Federal Reserve's target level of 2.0 percent and that is higher than when the Commission approved the Company's last ROE rate.[285] That increase in inflationary pressures prompted the Federal Reserve to implement aggressive actions to normalize monetary policy, including raising interest rates.[286] This increase has, by extension, resulted in investors expecting a higher return.[287] As noted below, commissions throughout the country have also noted this, which is reflected in the increase in authorized ROEs during 2024.

In addition, it is undisputed that the increase in treasury rates and core inflation caused "a substantial increase in the cost of equity since" the 2020 rate case.[288] Specifically, as demonstrated in Figure 2 of Ms. Bulkley's pre-filed rebuttal testimony, "the yield on the 30-year treasury bond increased by approximately 273 basis points and core inflation increased 170 basis points from the time [she] filed [her] testimony and [her] rebuttal evidence in the Company's 2020 rate proceeding to the time [she] filed [her] rebuttal testimony in this proceeding at the end of September 2024."[289] In the 2020 GRC proceedings, the Commission used the fact of a less significant decrease in treasury rates to justify a reduction in ROEs for both DEU and the Company (in the 2019 DEU case, an ROE decrease from 9.85 percent to 9.5 percent; in the 2020 RMP case, an ROE decrease

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[285] Phase I Direct Testimony of Anne E. Bulkley Direct at lines 356-360 ("Bulkley Direct").
[286] *Id.* at lines 407-415.
[287] *Id.* at lines 474-77.
[288] Phase I Rebuttal Testimony of Ann E. Bulkley at lines 81-82 ("Bulkley Rebuttal").
[289] Hr'g Tr. at 335:1-8 (Dec. 10, 2024); *see also* Bulkley Rebuttal at 7.

from 9.8 percent to 9.65 percent).[290] The Commission has previously noted that an increase or decrease in federal treasury rates is correlated to an increase or decrease in ROE.[291]

When asked about the increase in treasury rates during the Phase I hearing, Dr. Woolridge, the OCS's ROE witness, confirmed that, since the 2020 GRC, the cost of equity has indeed increased:

> Q. Okay. So I take it, since in 2020 you recommended a 9 percent—and I understand that there's an alternative there, but you recommended a 9 percent, and then earlier this year you recommended a 9.25 percent, and then now you've got a current recommendation of 9.375 percent, that you agree that the cost of equity since 20—or since the year 20[20] has increased?
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> A. Oh, yeah. I mean, authorized—I mean, third—fourth quarter of 2020, the long-term interest rate hit an all-time low of 1.3 percent at 30-year treasury yield. You know, that was also the year of the lowest authorized ROEs in the country for electric and gas companies.[292]

No other party disputes that treasury rates, interest rates, and inflation have increased substantially since 2020, all of which increase the cost of equity. Figure 15 from Ms. Bulkley's Rebuttal Testimony demonstrates that Dr. Woolridge's own analytical results indicate a higher cost of equity than in the 2020 rate proceeding, and every one of his model results showed an increase in the cost of equity and in his ranges.[293] Dr. Woolridge also updated his results in surrebuttal testimony to reflect the admitted increase in the cost of equity.[294] Thus, while the Commission states that it believes the OCS's analysis to be the most credible, it also should have acknowledged

[290] DEU GRC Order at 6 ("[D]eclining U.S. treasury rates since February 2014 could indicate a need to reduce DEU's authorized ROE."); DEU Cross Exhibit 8 (RMP 2020 GRC Order at 14 ("We find that lower U.S. treasury rates, compared to 2014, provide at least a starting point to our analysis indicating that a reduction to the ROE approved for RMP in 2014 seems appropriate.")).
[291] DPU Cross Exhibit 8 (RMP 2020 GRC Order at 16).
[292] Hr'g Tr. at 1116:2-14 (Dec. 13, 2024).
[293] Bulkley Rebuttal at lines 1302-1304.
[294] Phase I Surrebuttal Testimony of Dr. J. Randall Woolridge at lines 40-47 ("Woolridge Surrebuttal").

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that the cost of equity has significantly increased from 2020 to 2024, a condition that is contrary to its ROE determination, particularly in light of the ROE authorized in the 2020 GRC Order.

The increase in the cost of equity is further demonstrated by the undisputed fact that ROEs across the country have increased since 2020. Regulators throughout the country have, in response to worsening economic indicators, increased electric utility ROEs over the same period. As Ms. Bulkley summarizes in Figure 3 of her rebuttal testimony, the average ROE for electric utilities has increased as the 30-year treasury bond yield has increased during that same period.[295] In 2021, the average authorized ROE for electric vertically integrated utilities was 9.60 percent, and in 2024, the average increased to 9.82 percent, a greater than 20-basis-point increase.[296] Casey J. Coleman for the DPU and Dr. Woolridge for the OCS acknowledge this increase in electric utility ROEs since 2020.[297]

Despite this evidence, the Commission's Order does not account for, let alone acknowledge, that the cost of equity increased since 2020. Nor does the Order explain how that substantial increase is accounted for in a significant reduction in the Company's ROE over the ROE ordered in the 2020 GRC proceeding. The only apparent justification the Commission offers is its conclusion that all authorized ROEs over the past 20 years, including its 2020 ROE determination, were overstated, a conclusion that has not been adopted by any commission. The absence of that analysis is more than just a minor oversight. It renders the Commission's ROE determination defective.

In 2002, and addressing the factors required by the United States Supreme Court in setting the Company's rate of return, the Commission stated:

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[295] Bulkley Rebuttal at 8.
[296] *Id.*
[297] Phase I Direct Testimony of Casey J. Coleman at lines 826-860 ("Coleman Direct"); Phase I Direct Testimony of J. Randall Woolridge, Ph.D. at lines 454-473 ("Woolridge Direct").

> We are guided by U. S. Supreme Court decisions in the *Hope* (*FPC v. Hope Natural Gas Company*, 320 US 591 (1944)) and the *Bluefield* (*Bluefield Water Works v. PSC*, 262 US 659 (1923)) cases. From them, we learn that our rate-of-return decision ***should give investors the opportunity to earn a return on an investment in the Company comparable to the return the investor might earn in other investments of similar risk***, ***<u>and</u> it should be a return sufficient to attract capital on reasonable terms and to maintain a financially viable utility***. This points to the importance of an analysis of risk, and to the selection of comparable companies for that purpose. Investors' required return, the opportunity cost of capital, is thus the utility's cost of capital.[298]

Thus, an ROE is insufficient if it does not equate to a return commensurate with other investments of similar risk or is insufficient to attract capital on reasonable terms and to maintain a financially viable utility. Setting aside the Commission's conclusion that ROEs have allegedly been overstated for 20 years, the Commission does not explain how, when the cost of equity has increased since 2020, this standard could possibly be satisfied through a reduction in the Company's ROE.

b. Regulatory Conditions Have Not Improved for the Company Since 2020 as the Commission Claims.

The Commission's ROE determination is also premised upon the Commission's conclusion that RMP's relative risk has been reduced since 2020. In an initial attempt to support that point, the Commission claims: "It is well known that utility stocks are generally less risky than many other types of stocks."[299] But the Commission does not cite to any evidence to support that statement, nor is it correct. As Ms. Bulkley demonstrated in her pre-filed direct testimony:

> Since the beginning of 2023, utility stocks have significantly underperformed the broader market, as Treasury bond yields have increased to levels greater than the dividend yields of utility stocks. For example, as shown in Figure 5, since January 1, 2023, the yield on the 30-year Treasury bond has increased by approximately 68 basis points, while the share prices for the vertically-integrated electric utilities included in my proxy group (discussed in the

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[298] *In the Matter of the Application of Questar Gas Company for a General Increase in Rates and Charges*, Docket No. 02-057-02, Report and Order, Dec. 30, 2002, at 20 (emphasis added).
[299] Order at 29.

> following section) have *declined* by 3.16 percent and the S&P 500 Index has *increased* approximately 37.45 percent. The stock price underperformance for the utility sector indicates that the cost of equity has increased with the increase in interest rates.[300]

Other parties do not dispute this discrepancy. She also showed that underperformance on Figure 5 of her direct testimony.[301] It is because of this reality that the average of authorized ROEs for vertically integrated utilities throughout the United States have gone up, not down, since 2020.[302] Thus, the record evidence shows that utility stocks are more, not less risky, as compared to the market during the relevant periods covered by this case.

In addition, the Commission attempts to support its conclusion that the Company is less risky now than it was in 2020 by citing generally to regulatory mechanisms or Utah statutory provisions. However, the only regulatory mechanism cited by the Commission, the EBA, is not new and was also in effect in 2020. As such, the existence of the EBA cannot be used to justify a claim that the Company's risk has been reduced since 2020. Furthermore, as Ms. Bulkley and other ROE witnesses point out, other utilities in the proxy groups have the same kind of mechanism.[303]

Nor are the statutory provisions cited by the Commission necessarily risk-reducing. The Commission alludes to Utah Code § 54-24-1 *et seq.* (the Wildland Fire Planning and Cost Recovery Act) that allows the Company to recover prudent investments and expenses related to wildfire mitigation efforts. However, as this very case demonstrates, that statute does not necessarily reduce the Company's financial risk. Under that statute, the Commission rejected the Company's 2023 Revised Plan and denied it recovery of the vast majority of its capital investment costs and expenses to mitigate wildfire risks. Thus, rather than reducing the Company's financial

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[300] Bulkley Direct at lines 490-498.
[301] *Id.* at lines 499-540.
[302] Woolridge Direct at lines 461-467.
[303] Bulkley Rebuttal at lines 1204-1209.

risk, that statute, as applied by the Commission here, has increased the Company's risk because the Company has an obligation to mitigate fire risk, which the Commission is refusing to fund. That decision will not be viewed by the market as regulatorily supportive of the Company.

Further, the Commission cites to statutes it states provide wildfire liability protection and a damages cap for fire liability civil lawsuits for certain wildfires. While the Company does not dispute the existence of those statutes, the Commission does not explain how their existence more than offsets the increased risk to the Company from the growing risk of wildfires and having wildfire mitigation obligations that may be unfunded, increased insurance costs, and an increase in the cost of equity. Nor does the Commission cite to any evidence that the Company's risk is less than other comparable utilities. It is not sufficient for the Commission to merely *assume* that the Company is less risky than similarly situated utilities.

Dr. Woolridge, who the Commission liberally cites to in suggesting that the Company's regulatory risk justifies a lower ROE, *did not state* that the existence of these statutes was cause to *reduce the ROE*. Rather, he cites them for the proposition that there should not be an *ROE premium*. In fact, after reviewing the very same statutes to which the Commission cites in its Order, Dr. Woolridge states: "The bottom line is that there is no need to provide a premium ROE to RMP for wildfire risk."[304] He then notes that both he and Ms. Bulkley *did not* make an upward adjustment in the ROE for wildfire risk.[305] However, the Commission cites these statutes and Dr. Woolridge's testimony to claim that RMP's ROE should be *decreased* due to the existence of the cited Utah statutes, a position that the OCS and the Company witnesses do not support. Specifically, the Commission states in the Order, after discussing the statutes: "For these and other

[304] Woolridge Surrebuttal at lines 112-113.
[305] *Id.* at lines 136-141.

reasons . . . we find substantial evidence supports a downward risk-related adjustment to the ROE."[306] This is an improper basis for a downward adjustment by the Commission.

2. The Commission Improperly Ignores RMP's ROE Analysis.

The Commission identifies two aspects of the Company's ROE analysis that it uses to justify entirely ignoring RMP's ROE analysis. First, it states that "RMP's estimated growth rate and equity risk premium used in [its] models' analyses are based on projected growth rates that are completely unrealistic and produce unreliable results."[307] Second, the Commission states that the Company's analysis "[r]elies exclusively on the three- to five-year earnings per share ("EPS") projections from Value Line and Wall Street analysts to model long-term growth" and "[t]he evidence strongly shows these data produce an improper upward ROE bias. For example, applying these growth rate and EPS projections in RMP's DCF, CAPM, and ECAPM modeling produce long-term growth rates that are significantly greater than the growth of the overall economy, which is both a logical and mathematical impossibility."[308] These statements are near verbatim recitations of statements from Dr. Wooldridge's testimony. But they are incorrect.

First, Dr. Woolridge's analysis relies on the very same EPS projections as Ms. Bulkley from Wall Street analysts and also relies on a growth rate that is higher than the long-term GDP growth rates. Specifically, in his direct testimony, Dr. Woolridge states: "Giving primary weight to the projected growth rates of Wall Street analysts and Value Line, but recognizing the upward bias nature of these forecasts, …. I will use the midpoint of the range."[309] Similarly, later on he states: "Given that I rely primarily on the DCF model and that RMP's investment risk is a little

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[306] Order at 29.
[307] *Id.* at 25.
[308] *Id.*
[309] Woolridge Direct at lines 1176-1177.

below the average of the proxy groups, I believe that the common equity cost rate for RMP is in the 9.00%-9.50% range."[310]

Second, while Dr. Woolridge suggests that Ms. Bulkley's growth rates used in her CAPM exceed GDP and therefore cannot be relied upon, using Dr. Woolridge's own analysis, his growth rates would suffer from this same flaw. In Dr. Woolridge direct testimony, he takes the position that GDP growth in recent decades is more appropriately used in the current market, suggesting a range from 4.0 to 5.0%.[311] As shown in his Exhibit JRW-5, he relies on a growth rate of 5.85% in his CGDCF model, and his Exhibit JRW-10 from his surrebuttal testimony updates that growth rate to 6.05% for his proxy group and 6.15% for Ms. Bulkley's proxy group.[312] These figures are only slightly lower than Ms. Bulkley's median growth rate in her direct testimony (6.23%) and her median growth rate in rebuttal testimony (6.54%).[313] As such, if the Commission believes that Ms. Bulkley's analyses are flawed due to this constraint, then Dr. Woolridge's analysis also cannot be relied upon.

Third, the Commission is incorrect when it states that RMP acknowledged that its analysis would result in corporate profits, over the long term, outpacing GDP.[314] Ms. Bulkley did not testify that her analysis assumed that corporate profits would exceed GDP in the long run as the Commission states.[315] She made clear that the growth rate was, "not my DCF analysis that I'm using to set the cost of equity. It is the market return overall, and as I mentioned, I've looked at five different sources that put the market return right where history has provided and where the

[310] Woolridge Direct at line 1485.
[311] Woolridge Direct at lines 1858-1860.
[312] Woolridge Direct, Exhibit JRW-5 at 1; Woolridge Surrebuttal, Exhibit JRW-10 at 1.
[313] Bulkley Direct, Exhibit AEB-4; Bulkley Rebuttal, Exhibit AEB-2R.
[314] Order at 25.
[315] Hr'g Tr. at 430:1-14 (Dec. 10, 2024).

federal reserve of New York has indicated is the most consistent outcome."[316] She also testified that the resulting market return used in estimating the market risk premium ("MRP") is consistent with the long-term historical average actual return in the market from 1926 to the present, which shows the return is reasonable.[317] She demonstrated in her direct testimony that more than 50 percent of the time, based on historical data, the market return was greater than the return she used to estimate the MRP used in her CAPM.[318] Therefore, based on actual observed data, the MRP she used is not unreasonable. Further, she noted that other commissions have recognized the methodology that she used to estimate the MRP and a market return that is generally consistent with the return that she relied upon and provided a study by the Federal Reserve Bank of New York, the key conclusions of which supported her analysis.[319] The Commission did not recognize any of this evidence.[320] Ms. Bulkley also demonstrated in her rebuttal testimony that the assumptions used by Dr. Woolridge in his CAPM analysis also result in implied long-term growth rates for the overall market that exceed his expectation of GDP growth.[321]

Further, Dr. Woolridge conceded the point that the market return is not related to U.S. GDP both in his testimony and on cross-examination. Specifically, in his direct testimony, he noted that, during the last two years, as the EPS for the S&P 500 has grown at a faster rate than U.S. nominal GDP, some have pointed to the differences between the S&P 500 and GDP to explain that result.[322] Further, he cited to a Seeking Alpha article entitled *How Do We Have 18.4% Earnings Growth In*

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[316] Hr'g Tr. at 431:20-432:2 (Dec. 10, 2024).
[317] Hr'g Tr. at 428:7-17 (Dec. 10, 2024).
[318] *Id.*
[319] Bulkley Rebuttal at 48-52.
[320] Bulkley Direct, at 42, Figure 9.
[321] Bulkley Rebuttal at 87, Figure 21.
[322] Woolridge Direct at lines 1922-1923.

A 2.58% GDP Economy? During cross-examination, he admitted, as the article observes, that the S&P 500 is not limited to the U.S. economy and, for that reason, EPS can exceed GDP.[323]

While the Commission credits Dr. Woolridge's CAPM analysis as being more credible, the Commission failed to recognize that one of the studies on which he relies to establish his MRP specifically notes that the results of the study "cannot be interpreted as the RPE [required equity premium] of the market nor as the RPE of a representative investor".[324] It is unreasonable to suggest that the MRP assumption relied upon by Dr. Woolridge is more credible when the source of that data specifically states it should not be used in the manner that Dr. Woolridge relied on it.

The Commission also states, incorrectly, that "RMP's bond yield plus risk premium ('BYRP') modeling was also discredited because of, among other reasons, the degree of influence of authorized ROEs from other state commissions in that analysis. As persuasively argued by OCS, and not disputed by RMP, a fundamental component of the BYRP model is commission behavior (i.e., the authorized ROEs set by commissions over a historical period), and not investor behavior."[325] This statement by the Commission is incorrect. Ms. Bulkley did dispute this point on page 98 of her rebuttal testimony. There, she notes that, while ROEs are commission behavior, investors consider commission behavior when they make investment decisions.[326] She also points out the inconsistency in Dr. Woolridge's position—he suggests that BYRP cannot be relied upon because the ROEs are commission behavior, but then he uses the very same authorized ROE data to support his recommended ROE.[327] The Order does not reconcile Ms. Bulkley's rebuttal of this

[323] Hr'g Tr. at 1144-1150 (Dec. 13, 2024).
[324] Bulkley Rebuttal at 84, Pablo Fernandez, Diego Garcia de la Garza, and Lucia Fernandez Acin. "Survey: Market Risk Premium and Risk-Free Rate used for 96 countries in 2024," IESE Business School, at 11, March 11, 2024, (emphasis added).
[325] Order at 25-26.
[326] Bulkley Rebuttal at lines 1936-1951.
[327] Woolridge Direct at lines 307-543.

issue or address the fact that Dr. Woolridge uses the very same authorized ROEs to support his own results. Further, it is not possible to reconcile the use of authorized ROE data to justify his model results and rely on the Werner and Jarvis study to suggest that authorized ROEs have exceeded the cost of equity. This is just another example of the inconsistencies that carry throughout Dr. Woolridge's analyses.

Finally, the Commission states: "According to OCS testimony, the 2020 GRC award was one of the highest authorized ROEs awarded for electrical utilities in the United States in the fourth quarter of 2020" and cites to Dr. Woolridge testimony at hearing for that proposition.[328] This statement is also unsupported. The BYRP data for 2020 provided in Exhibit AEB-6R shows that the quarterly average ROEs were as follows: Q12020: 9.72%; Q22020: 9.58%; Q32020: 9.30%; Q42020: 9.56%.[329] Given that these are averages, it is clear that a 9.65 percent ROE could not have been the highest or one of the highest during 2020.

3. <u>The Order's Reliance on UTLCG's and OCS's ROE Ranges Is Contrary to Prior Commission Determinations.</u>

The Order states that "UTLCG's and OCS's recommended ROE ranges [are] credible and persuasive."[330] However, the UTLCG recommended an ROE derived from a range that is nearly identical to ROE ranges this Commission determined in 2020 were so low as to be unreasonable and not worth considering. Specifically, the ranges of UTLCG's equity analyses are as follows: the Constant Growth Discounted Cash Flow ("DCF") modeling produced an ROE range of 7.60 percent to 8.50 percent.[331] UTLCG's capital asset pricing model ("CAPM") analysis produced an ROE range of 8.28 percent to 8.80 percent.[332] The ranges rejected by this Commission as

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[328] Order at 28.
[329] Bulkley Rebuttal Exhibit AEB-6R.
[330] Order at 26.
[331] Bulkley Rebuttal at 105.
[332] *Id.*

unreasonably low in its RMP 2020 GRC order were 7.24 percent to 9.17 percent for the DPU, and 7.60 percent to 8.95 percent for the OCS.[333] Both of Mr. Garrett's models produced an upper boundary below these figures, and his lower boundaries are consistent with the lower end of the ranges proposed by the DPU and the OCS in 2020 that this Commission stated were unreasonable. The Commission does not explain how UTLCG's recommended ROE can possibly be considered "credible and persuasive" in the Order in light of the Commission's 2020 Order, let alone where the cost of equity has increased since 2020.

Further, as Ms. Bulkley points out, the results from Mr. Garrett's CAPM analysis, which he testified at hearing he favored over his DCF analysis, resulted in an authorized ROE range that is at "the very low end or below any authorized ROE for a vertically-integrated electric utility in a regulatory jurisdiction comparable to Utah *in over 40 years*."[334] The Order does not even discuss this disparity, let alone explain how Mr. Garrett's analysis could be "credible and persuasive" when it is far below any ROE this Commission has approved for decades.

With regard to the Commission's finding that the OCS's ROE analysis is "credible," the Order does not account for, let alone address, numerous arguments by Ms. Bulkley showing that the OCS analysis was flawed. For example, in her Figure 15, she shows how the results of Dr. Woolridge's analyses from 2020 to 2024 all demonstrate that his cost indicators have increased.[335] Further, her Figure 16 demonstrates that Dr. Woolridge has changed the weightings of his DCF model results to arrive at a desired result.[336] Specifically, in 2020, he recommended an ROE higher than his DCF result, yet, in 2024, he recommended an ROE that was 30 basis points lower than

[333] DPU Cross Exhibit 8 (RMP 2020 GRC Order at 15 n.7).
[334] Bulkley Rebuttal at lines 2198-2201 (emphasis added).
[335] Bulkley Rebuttal at 64, Figure 15.
[336] Bulkley Rebuttal at 65, Figure 16.

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his DCF results.[337] He provided no justification for the randomness of his weightings, regardless of the fact that he is dealing with the *same* utility just four years apart.

In addition, his CAPM cannot be reconciled with his DCF results, as Ms. Bulkley points out.[338] The Order does not note this inconsistency or explain how Dr. Woolridge's ROE recommendation can be explained in light of the result. Similarly, Ms. Bulkley's Figure 20 shows that, using the market risk premium that Dr. Woolridge applies and the corresponding Rf rates for the sources he relies on, the resulting return on the market is 7.75% to 9.38%, which is an irrational and inexplicable result and, as noted above, in the range this Commission previously stated was unreasonably low.[339] Specifically, the market risk premium suggests returns on the overall market that are lower than Woolridge's DCF results. Considering that utilities have a beta of less than 1.0, the resulting ROE would be inconsistent with Dr. Woolridge's own model results.

Finally, the Order suggests that Dr. Woolridge's model results are based on growth rates using numerous sources.[340] But Dr. Woolridge admitted that his ROE recommendation was primarily the results of his projected EPS growth rates.[341] He discounted the significance of many of the other growth rates that he suggested he considered.[342]

4. <u>The Commission's Reliance on Allegedly Overstated ROEs Is Improper and Not Supported by Substantial Evidence.</u>

A central basis for the Commission's reduction in the Company's ROE is its conclusion that, over at least the last 20 years, the authorized ROEs for utilities (including those approved by this Commission itself) across the country have been overstated. Specifically, the Order states:

[337] Bulkley Rebuttal at 65, Figure 16.
[338] Bulkley Rebuttal at 85, Figure 20.
[339] Bulkley Rebuttal at 85, Figure 20.
[340] Order at 27 n.45.
[341] Woolridge Direct at lines 1176-1178.
[342] Woolridge Direct at lines 1176-1178.

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> The record also includes evidence showing that authorized ROEs nationwide have likely overstated the actual cost of capital in recent years. In support of this assertion, OCS provided evidence from various articles and studies, including a 2022 and 2024 study, which found, among other things, that '[t]he gap between authorized ROEs that are [higher than] the cost of equity benchmarks[.]' and ROEs requested by utilities and the ROEs 'granted by regulators respond more quickly to rises in market measures of capital cost than declines. The time adjustment for decreases is [longer than] for increases.' This evidence supports that utility-authorized ROEs between 1980 and 2022 consistently overstated the actual cost of equity capital. RMP offers arguments to rebut this evidence, but we find substantial evidence supporting the position of OCS more credible and persuasive.[343]

This finding and conclusion by the Commission is flawed, caused the Commission to improperly discount other evidence that favored an ROE increase (despite the Company seeking to hold ROE flat), and does not account for any of the inconsistencies in the relied-upon study.

First, the OCS did not provide various articles and studies on this topic as the Commission states. The OCS relied on one article. Specifically, Dr. Woolridge cites to a Wall Street Journal article entitled: "Utilities Have a High-wire Act Ahead."[344] That article in turn referenced a study by Karl Werner and Stephen Jarvis entitled, "Rate of Return Regulation Revisited."[345] That study, which is based in part on an assessment of UK-authorized ROEs that are based on a very different regulatory and capital markets environment than in the U.S. (as pointed out by Ms. Bulkley) argues that regulators have been approving ROEs that are higher than the cost of equity benchmarks.[346] Relying on that study, which the Commission characterizes as "substantial evidence," the Commission concludes that ROEs authorized by commissions throughout the U.S. for at least the past 20 years are overstated, including this Commission's ROE decision issued just four years ago

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[343] Order at 28-29.
[344] Woolridge Direct at line 496.
[345] *Id.* at 24 n.12.
[346] Bulkley Rebuttal at lines 493-504.

in 2020. The cited study is neither substantial evidence, nor a proper basis on which to make such a definitive finding and conclusion.

The Commission did not in this proceeding hear from any witness that had first-hand knowledge regarding the cited study, how it was conducted, or the underlying assumptions of the study. Nor did any party submit evidence demonstrating that the study has become generally accepted in the economic community, that it is reliable, or that it is based on sufficient facts and data to support the alleged conclusions. Nevertheless, the Commission's Order adopts the study as "expert" evidence, which the Commission treats as definitive on the question of whether authorized ROEs have been overstated. Moreover, the Commission did not review any of the underlying data used in the study or any materials from any of the commission proceedings referred to in the study. No party cited to any case or proceeding in which the study has been accepted as a basis to make a downward adjustment in ROE. Indeed, no order has been identified in any other case or commission proceeding that even cited to the referenced study. Despite all of this, the Order elevates the study and treats it as the only authority on the issue of whether authorized ROEs have been overstated nationwide for over 20 years despite other contrary evidence.[347] And the Commission makes no effort to explain why the contrary evidence does not call into question the study.

Second, the Commission's reliance on the study also caused it to commit a second evidentiary error—rejecting consideration of evidence regarding contemporaneous authorized ROEs (the average of which is 9.82 percent) because the Commission concludes that "the expert testimony that historic authorized ROEs nationwide have overstated the actual cost of capital for

[347] Order at 28-29; *see* Bulkley Rebuttal at 497-499.

a significant period."[348] Prior Commission rate case orders have repeatedly emphasized the relevance of other authorized ROEs, particularly relatively recent authorized ROEs.[349] In this proceeding, it is undisputed, and conceded by the OCS and DPU, that recent authorized ROEs tended to track interest rates.[350] Further, OCS does not dispute the increase in authorized ROEs and the cost of equity.[351] Further, as noted, Dr. Woolridge relied on ROE data from other commissions to justify his own ROE recommendation.

Third, the Order provides no analysis of the arguments Ms. Bulkley provided to counter the study. Specifically, in her rebuttal testimony, Ms. Bulkley identified that the Werner and Jarvis study is based on assumptions that do not hold. Specifically, she demonstrated that:

- There is not a 1-to-1 relationship between yields on T bonds and authorized ROEs, as the authors contend—Ms. Bulkley showed, through a regression analysis, in her Exhibit AEB-7 that this assumption is incorrect.

- The form of the CAPM relied upon in the article does not produce accurate results in all market conditions, contrary to the assumption of the authors; and

- Ms. Bulkley explains that there is a significant difference between U.S. and UK regulation, contrary to the authors' assumption. She points out that the authors themselves acknowledge that "there are many differences between the utility sector and investor environment in the US and UK."[352]

The Order does not explain how the article can be deemed a definitive authority on the issue of whether ROEs have historically been overstated when it is based on assumptions that are not correct.

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[348] Order at 30.
[349] DPU Cross Exhibit 8 (RMP 2020 GRC Order at 15); Report and Order, *Application of Dominion Energy Utah to Increase Distribution Rates and Charges and Make Tariff Modifications*, Docket No. 19-057-02 at 6 (Feb. 25, 2020).
[350] Woolridge Direct at 20-21; Coleman Direct at lines 169-185.
[351] Woolridge Direct at 21, Table 3, lines 511-513.
[352] Bulkley Rebuttal at lines 497-499.

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D. The Commission’s Cost of Capital Determination Relies on Incorrect Assumptions, an Incorrect Prudence Standard, and an Incorrect Assessment of Its Own Precedent.

As the Commission notes in the Order, the Company sought in this proceeding a hypothetical capital structure comprised of 50 percent equity and 50 percent debt. The Commission further notes that the Company sought the hypothetical capital structure "'as a form of regulatory support to preserve [its] credit worthiness and maintain certain credit metrics'" in the face of unprecedented wildfire liability and its capital expenditure plan that, without support, would place the Company is a highly leveraged and risky position.[353] No party disputes that the Company is in a highly leveraged and more risky financial position than has been the case in recent general rate case proceeding. In rejecting the Company’s request, the Commission concluded:

> We do not believe Utah ratepayers should be burdened with the additional costs of RMP’s proposed hypothetical 50 percent equity ratio. . . . RMP’s current capital position is primarily a result of PacifiCorp’s own actions. Multiple catastrophic wildfires occurred in PacifiCorp’s service territory on or around Labor Day, 2020. A class action lawsuit—*James*—was commenced on September 30, 2020. On October 20, 2020, additional plaintiffs were added and the demand for damages was increased to over $600 million. PacifiCorp was thus on notice of allegations that the fires were caused by its own negligence as of September 30, 2020. Yet PacifiCorp paid dividends to BHE of $150 million in 2021, $100 million in 2022, and $300 million in 2023. On June 12, 2023, the trial in *James* concluded with a verdict against PacifiCorp for all four Labor Day fires. The jury’s verdict included findings that PacifiCorp was grossly negligent, reckless and willful, and that its actions were a cause of harm to the entire class in *James*. The jury also found PacifiCorp liable for punitive damages to class members. Since the *James* verdict was issued, additional jury verdicts totally several hundred million dollars have been reached. . . . In 2023, PacifiCorp recorded significant wildfire liability accruals which caused its net income to decline to a negative $488 million. The combination of negative net income and dividend payments of $300 million resulted in a reduction in the retained earnings component of common equity balance by almost $800 million in 2023. . . .

[353] Order at 32-33 (quoting Hr’g Tr. at 139:13-17).

> The only reasonable conclusion that can be reached is that RMP's common equity position significantly declined because of the liability accruals it incurred because of the 2020 wildfires in Oregon and was exacerbated by the payment of $550 million in dividends at a time when it should reasonably have concluded that it had a risk of enormous liability for these wildfires. . . . Simply put, Utah customers of RMP should not pay higher rates because of the fallout from the Oregon wildfires and depletion of PacifiCorp's cash reserves by the payment of $550 million in dividends.[354]

It also stated that the only precedent supporting the application of a hypothetical capital structure is distinguishable because, in that proceeding, all parties agreed to the structure.[355] Thus, the Commission rejected the Company's proposed capital structure because it concluded the Company's financial situation is the result of the Company's own alleged negligence relative to the Oregon wildfires; the Company was, according to the Commission, imprudent in issuing dividends between 2021 and 2023 in light of the pending *James* case (which the Company is appealing); and there is no precedent that supports the Company's request. Each of these conclusions is incorrect.

First, it is error for the Commission to reject the Company's proposed capital structure on the basis of assumed negligence by the Company concerning the Oregon 2020 Labor Day wildfires. While the Company recognizes the *James* verdict, that verdict is on appeal and likely to be reversed based on the results of a multi-year investigation by the ODF.[356] ODF recently issued its report, which concluded that the Company did not contribute to the main fire that caused the most damage, a conclusion that is contrary to the verdict.[357] The ODF report was not available for the *James* trial, but was provided to the Commission in this proceeding. Thus, the Commission should not have simply relied on the *James* verdict to assert the Company's financial condition

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[354] Order at 39-41.
[355] *Id.* at 38.
[356] RMP Cross Exhibit 7.
[357] *Id.* at A2, A14.

resulted from the Company's negligence because it has been determined by ODF that the Company *did not contribute* to the fire that resulted in the primary damage at issue in *James*. As is now clear, those fires and the ensuing litigation arising out of them were not in the Company's control, nor was the Company able to avoid the fallout that ensued from the litigation as the Order claims. By failing to account for the ODF report, the Commission's capital structure ruling is flawed.

Second, and relatedly, the Commission does not rely on a proper prudence standard in concluding that the issuance of dividends during the pendency of the *James* case was imprudent. As noted above, under the prudence standard, one only considers what was known or knowable at the time a utility decision was made and whether that action was reasonable in light of that information.[358] The *James* verdict and associated damages award were not known or foreseeable at the time the dividends were issued as the *James* verdict did not issue until years and months later.[359] Moreover, when the *James* case was filed, the Company (consistent with standard utility practice) followed Generally Accepted Accounting Principles to estimate its probable liability and recorded that estimate, updating it each year as the case evolved.[360] As Ms. Kobliha explained, when the dividends were declared:

> [I]t was impossible for the Company to know what would come out of the James verdict, for example, and so we're assessing, you know, all the facts and information we have available at the time. . . . So it was—there was no way for me to predict that we would have this huge outstanding challenge that came from that verdict. So those dividends were paid, you know, looking at our policy and our capital structure and what was reasonable to get our equity to the level that was authorized. And as soon as that verdict came out, we actually had another dividend that we were intending to pay in 2023, and we

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[358] Utah Code 54-4-4(a).
[359] DPU Cross-Exhibit 4 (showing that the last of the dividends was paid out on January 25, 2023); Hr'g Tr. at 190:16-18 (Dec. 9, 2024) (noting that the *James* verdict was not issued until June 2023).
[360] Hr'g Tr. at 190:7-15 (Dec. 9, 2024); DPU Cross-Exhibit 6 at 2-3 (explaining the Company's estimate of probable liability with regard to the Oregon fire cases).

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> canceled that dividend as soon as the verdict came out because of the risk that was now put forth in front of us.[361]

Thus, the Company's issuance of the dividends followed normal Company protocol, taking into account the Company's estimated liability under GAAP principles while also ensuring that the Company would not be negatively impacted by the dividends being declared. These facts demonstrate that the Company acted prudently.

Further, had the Company not issued the dividends, there is no evidence its current financial situation would be significantly improved. As Ms. Kobliha stated, those funds would not have just been held in reserve, "that $550 million of cash would have been used for potentially something. I can't say necessarily what, and so it's hard for me to conclude what—what the world would look like that I'm not in."[362] No party offered any evidence to the contrary. Therefore, the Commission's assumption that the payment of the dividends resulted in the Company's financial position is unsupported. In fact, as noted in DPU Cross-Exhibit 4, the dividends paid by the Company in 2021 to 2023 are, on an annual average basis, less than the dividend amounts paid out in most other years prior to the *James* case.[363] During those years, the Company also had pending litigation matters, even significant ones. The mere existence of lawsuits did not render the issuance of those dividends imprudent because the Company followed GAAP principles, did its best to estimate the probable liability, and issued dividends in amounts that did not present concerns at the time of issuance. The same is true here.

The Commission's assertion that the Company was on notice as of October 20, 2020, of "over $600 million" in claimed damages in the *James* case does render the Company's issuance of dividends imprudent. The Company's best information did not indicate potential liability even

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[361] Hr'g Tr. at 291:21-292:12 (Dec. 10, 2024)
[362] Hr'g Tr. at 191:10-13 (Dec. 9, 2024).
[363] DPU Cross-Exhibit 4 at 4.

approaching the damages figure resulting from *James*. As Ms. Kobliha testified, the Company was unaware of any action or inaction on its part that could have caused the fires, and the Company in its history prior to *James* had never been held liable for merely not de-energizing lines, which is the only basis on which the *James* jury determined the Company was liable.[364] It is not reasonable for a utility to be expected to assume that its likely liability will be equal to or greater than the damages amount asserted by every plaintiff. The Company's approach to the *James* case was entirely consistent with how it has approached other lawsuits in the past.

As a final point, the Commission's assertion that there is no precedent where the Commission approved a hypothetical capital structure to provide regulatory support and to strengthen a utility's financial position in the absence of an agreement by all parties is incorrect.[365] In its Phase I Post-Hearing Brief in this matter, the Company cited to other dockets in which the Commission approved a hypothetical capital structure over the objection of parties specifically to assist a utility to cope with financial and market pressures.[366]

E. The Commission Should Review and Reverse or Order Rehearing on Its Ruling that the Company Cannot Recover Washington Climate Commitment Act ("WCCA") Costs.

1. <u>The Commission Should Review and Reverse Its Interpretation and Application of the 2020 Protocol.</u>

a. Chehalis Is a "System Resource" Rather Than a "State Resource" for Purposes of the 2020 Protocol Cost Allocation and Assignment.

The 2020 Protocol provisions relevant to the Order focus on how to allocate the costs of resources that are used to provide power to customers in the six states served by the Company. For each resource ("Resource") the Company procures to provide power to its customers (whether by

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[364] Hr'g Tr. at 281:1-18 (Dec. 10, 2024).
[365] Order at 38.
[366] *See* Rocky Mountain Power's Post-Hearing Brief Addressing Phase I Issues, Docket No. 24-035-04, at 10 (Jan. 30, 2025).

ownership, contract, or to comply with state rules), the costs and benefits of that Resource must be divided up among the six states. The 2020 Protocol provides an agreed-upon methodology for that division.

Under the 2020 Protocol, Company "Resources [are] allocated to one of two categories for inter-jurisdictional allocation purposes: State Resources or System Resources."[367] The 2020 Protocol defines a "Resource" to include "a Company-owned generating unit, plant, mine, long-term Wholesale Contract, Short-Term Purchase and Sale, Non-firm Purchase and Sale, or QF contract."[368] The Chehalis plant is a "Company-owned generating unit."

For "System" resources used by Utah customers, the Commission acknowledged in its order approving the 2020 Protocol that the Protocol's cost allocation criteria require that "new resources with a commercial operation date before January 1, 2024 will continue to be treated as system resources, and assigned and allocated based on the system generation factor[.]"[369] Chehalis started commercial operations in October 2003, and the Company acquired the plant in 2008.[370] Thus, there is no dispute that Chehalis is an existing Resource that was online before 2024. The terms of the 2020 Protocol and the Commission's order approving it place Chehalis in the System Resource category for cost allocation purposes.

In addition, the 2020 Protocol provides that "[g]eneration-related dispatch costs and associated plant will be" System allocated.[371] This makes sense because, among other reasons, it is difficult to quantify and situs-assign the impact that incremental generation costs, such as taxes

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[367] *Application of RMP for Approval of the 2020 Inter-Jurisdictional Cost Allocation Agreement*, Docket No. 19-035-42, Application filed Dec. 3, 2019, Ex. RMP___JRS-1, at Section 3.1.2 ("2020 Protocol").
[368] *Id.* at Appendix A.
[369] *In the Matter of the Application of Rocky Mountain Power for Approval of the 2020 Inter-Jurisdictional Cost Allocation Agreement*, Docket No. 19-035-42, Order Approving 2020 Protocol, April 15, 2020, at 4 n.11.
[370] State of Washington Energy Facility Site Evaluation Council, "Chehalis Generation Facility," https://www.efsec.wa.gov/energy-facilities/chehalis-generation-facility.
[371] 2020 Protocol, Section 3.1.7.

or environmental compliance costs, have on system plant dispatch. When the costs and benefits of a Resource are being allocated, the allocation is distorted if certain costs or benefits are removed from the calculation required by the 2020 Protocol.

To be categorized as a "State Resource" under the 2020 Protocol, a Resource must fit into one of three categories identified in Section 3.1.2.1: "Demand-Side Management Programs," "Portfolio Standards," or "State-Specific Initiatives."[372] The analysis in the Order includes references to "Portfolio Standards" and "State-Specific Initiatives,"[373] which are defined terms in the 2020 Protocol.

- "Portfolio Standard" is defined in the 2020 Protocol to mean "a law or regulation that requires PacifiCorp to acquire: (a) a particular type of Resource, (b) a particular quantity of Resources, (c) Resources in a prescribed manner or (d) Resources located in a particular geographic area."[374]
    - The "portion of costs associated with Interim Period Resources[375] acquired to comply with a State's Portfolio Standard adopted, either through legislative enactment or by a State's Commission, that exceeds the costs PacifiCorp would have otherwise incurred, will be allocated on a situs basis to the Jurisdiction adopting the Portfolio Standard."[376]
- "State-Specific Initiatives" include "Resource[s] *acquired* in accordance with a State-specific initiative," which may include, but are not limited to, Resources *acquired* to comply with "incentive programs, net-metering tariffs, feed-in tariffs, capacity standard programs, solar subscription programs, electric vehicle programs, and the acquisition of renewable energy certificates."[377] The 2020 Protocol notes that "[h]istorically, [State-Specific Initiatives] . . . have not included local fees or taxes

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[372] *Id.* at Section 3.1.2.1. If Resources do not fit in one of the three "State" categories, they "are System Resources, which constitute the substantial majority of PacifiCorp's Resources." *Id.* at Section 3.1.2.
[373] Order at 24-25.
[374] 2020 Protocol, Appendix A.
[375] In the 2020 Protocol, the "Interim Period" refers to January 1, 2020, to December 31, 2023, the period during which the 2020 Protocol approved by the Commission remains in effect. *Id.* at Section 2 (RMP Exhibit 47 at 19). On April 12, 2023, the Company submitted its application requesting the Commission's approval to extend the 2020 Protocol through December 31, 2025, effective January 1, 2024. *See In the Matter of the Application of Rocky Mountain Power for Authority to Extend the 2020 Inter-Jurisdictional Cost Allocation Agreement Through December 31, 2025*, Docket No. 20000-641-EA-23 (Record No. 17280), Notice of Application (April 17, 2023). The Commission approved the Company's request to extend the 2020 Protocol at its Open Meeting on December 28, 2023.
[376] 2020 Protocol, Section 3.1.2.1.
[377] *Id*. (emphasis added).

related to the ongoing operation of existing transmission and generation facilities within a State."[378]

- The allocation and assignment rule for these Resources is clear: "Costs and benefits associated with Interim Period Resources *acquired* in accordance with a State-specific initiative will be allocated and assigned on a situs basis to the State adopting the initiative."[379]

The 2020 Protocol speaks to ***acquisition*** of the Resource whose costs and benefits are being allocated. Thus, it is only when the Company *acquires* a Resource as part of a state policy initiative that Section 3.1.2.1 and its "State Resources" category (with its attendant cost allocation and situs assignment criteria) come into play. Specifically, to qualify as a State Resource, the Company must have *acquired* the Resource because of a state-imposed requirement to procure specific types of resources. For example, this could include renewable generation procured by the Company to comply with a state's Portfolio Standard, capacity standard, or incentive program.

There is no evidence or even inference that Chehalis was "acquired to comply with" a Portfolio Standard or was "acquired in accordance with" a State-Specific Initiative program, including the CCA. In fact, as noted above, Chehalis was acquired by the Company long before the CCA was implemented by Washington. While Chehalis is certainly impacted by Washington's state mandates, under the terms of the 2020 Protocol, adding new state-imposed costs or surcharges to the operating costs of an existing Resource does not convert that Resource into a "State Resource." The criteria for designating a Resource in the Portfolio Standard or State-Specific Initiative category focuses on "Resources acquired in accordance with" the initiative.

Because the undisputed evidence is that Chehalis was acquired long before the CCA was implemented by Washington and was not acquired to satisfy whatever Washington policies

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[378] *Id.* at Section 5.8.
[379] *Id.* at Section 3.1.2.1. (emphasis added).

underlie the CCA, under the express terms of the 2020 Protocol, the Chehalis facility cannot be considered a Resource whose costs would be allocated as a State Resource, whether under the Portfolio Standard or State-Specific Initiative provisions of the 2020 Protocol.

i. The Legal Requirement that the Company Incur CCA Costs to Enable Chehalis to Serve Utah Customers Does Not Constitute a "State-Specific Initiative" or "Portfolio Standard" Subject to Situs Assignment.

The Commission's decision that CCA costs constitute a situs-assigned, State-Specific Initiative relies on the determination that the CCA "penalizes emissions but shields its own residents from incurring the associated costs."[380] There is a critical difference between a State-Specific Initiative or Portfolio Standard that would result in situs assignment of a Resource, on the one hand, and the Chehalis compliance costs mandated by the CCA, on the other hand. The difference is illustrated by contrasting the Washington state mandates that impact the operating costs and dispatch of Chehalis: the CCA and the Washington Clean Energy Transformation Act ("CETA").[381]

The Company agrees that CETA is a State-Specific Initiative under the 2020 Protocol, as it satisfies the definition of a State-Specific Initiative. CETA demands that the Company *procure* particular types of resources to provide power for Washington customers, with all incremental costs of CETA compliance appropriately situs-assigned to Washington. This would include any costs "that exceed the costs PacifiCorp would have otherwise incurred"[382] (i.e., all incremental costs associated with Resources acquired to comply with CETA are situs-assigned to Washington).

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[380] Order at 48 (quoting *RMP's Application for Approval of the 2024 EBA,* Docket No. 24-035-01, Order, Feb. 25, 2025, at 23-24).
[381] RCW Chapter 19.405, §§ 19.405.010 – 19.405.901 (2023).
[382] 2020 Protocol, Section 3.1.2.1 (describing a "Portfolio Standard").

For example, if PacifiCorp had to procure a resource to specifically meet the needs of CETA, the costs and benefits of that resource would be situs-assigned.

In this way, the costs of CETA are fully allocated and situs-assigned to Washington. Customers in Utah and other states are not required to pay for the Company's incremental costs to comply with CETA. The provisions that make no-cost allowances available to the utilities, including the Company, are included in the CCA statute, and the Washington Department of Ecology has not permitted those no-cost allowances to be allocated to non-Washington customers.[383] The Company's obligations under the CCA regime that are being applied in this case are a cost that is directly applied to power generation at a facility that is located in Washington, and none of those CCA obligations involve resource acquisition akin to a Portfolio Standard like CETA.

The CCA requires that the Company secure an allowance for each metric ton of carbon dioxide equivalent emitted from Chehalis; allowance costs are directly tied to the level of generation at the plant.[384] Compliance is demonstrated by retiring allowances for any GHG output from Chehalis within the State of Washington.[385] For energy from Chehalis allocated to serve customers outside Washington, the CCA imposes an obligation to obtain allowances proportionate to the cost-allocated share of Chehalis.[386]

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[383] Although the Company proposed that no-cost allowances should also be extended to the Company's customers in other states, the Washington Department of Ecology rejected the proposal and concluded that the CCA statute required that these no-cost allowances offset the cost burden of CETA compliance for Washington customers. State of Washington, Dep't. of Ecology, Publication 22-02-046, Concise Explanatory Statement Chapter 173–446 WAC Climate Commitment Act Program at 239 (Sept. 2022),https://apps.ecology.wa.gov/publications/documents/2202046.pdf).

[384] Response Testimony of Michael G. Wilding at lines 491-493 ("[T]here is no compliance obligation if there is no generation, and the amount of the compliance obligation is determined by the amount of generation.") ("Wilding Response"). *See also* RCW 70A.65.010(1) (defining "Allowance" as "an authorization to emit up to one metric ton of carbon dioxide equivalent.").

[385] Phase I Rebuttal Testimony of Ramon Mitchell, Docket No. 24-035-04, at lines 279–294.

[386] *Id.* at Exhibit A (summarizing incremental dollar-per-megawatt-hour for generation from Chehalis).

The CCA requirements do not involve resource procurement standards, but rather are functionally equivalent to the California cap-and-trade program, the Wyoming wind tax, and other state programs and taxes that increase dispatch costs—none of which are treated by the Commission as State-Specific Initiatives for cost allocation purposes.[387] Ultimately, the requirements applicable to Chehalis are driven by the levels of GHG emissions the CCA aims to reduce within and beyond the electric industry; they are separate from the generation portfolio standards that drive CETA.

ii. The Order Impermissibly Disconnects Allocation of Chehalis "Costs and Benefits."

Assuming for argument's sake that Chehalis qualified for treatment as a situs-assigned, State-Specific Initiative Resource, Section 3.1.2.1 of the 2020 Protocol requires that both the "*costs and* benefits" resulting from a State-Specific Initiative be "assigned on a situs basis to the State adopting the initiative."[388] For a Portfolio Standard Resource, Section 3.1.2.1 provides that "[t]he portion of costs associated with Interim Period Resources acquired to comply with a State's Portfolio Standard . . . that exceed the costs PacifiCorp would have otherwise incurred, will be allocated on a situs basis to the Jurisdiction adopting the Portfolio Standard."[389] The Portfolio Standard language provides a specific limit bounded by the "portion of costs" associated with a Portfolio Standard, but maintains the link between situs assignment of costs and benefits. Consistent with basic ratemaking principles, the 2020 Protocol provisions designating State Resources do not permit the assignment of costs to be disconnected from the assignment of benefits.

[387] Tr. Vol. I, p. 101; 2020 Protocol, Section 3.1.7.
[388] 2020 Protocol, Section 3.1.2.1 (emphasis supplied).
[389] *Id.*

The record identifies the costs the Company incurs to comply with CCA requirements, which includes "'an incremental $/MWh cost based on the GHG allowance price for the test period'" for any energy exported from Chehalis to Utah.[390] The substantial benefits of Chehalis power to Utah customers are also documented in the record. Energy purchased from Chehalis is a less expensive option than sourcing replacement energy from other market purchases, "'which are more expensive than the cost of fuel and GHG allowances combined.'"[391] Therefore, even accounting for the CCA compliance costs, generation from Chehalis results in substantial net benefits for Utah customers.

The 2020 Protocol requires that both the "costs and benefits" of a Resource classified as a State-Specific Initiative be situs-assigned if either is situs-assigned.[392] The Order does not comply with this requirement nor with the Commission's order approving the 2020 Protocol. Rather, the Order situs-assigns the CCA costs required to provide power to Utah customers entirely to Washington, but maintains the benefits Utah customers receive from their share of the power generated at Chehalis.

This approach is inconsistent with fundamental ratemaking standards. In ratemaking, utilities and regulators strive to allocate costs according to the long-standing and generally accepted principle of cost causation. The cost-causation principle compares "the costs assessed against a party to the . . . benefits drawn by that party."[393] When the 2020 Protocol situs-assigns a Resource, it is assigning the "[c]osts and benefits associated with Interim Period Resources

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[390] Direct Testimony of Ramon Mitchell, Docket No. 24-035-04, at lines 352-353 ("Mitchell Direct").
[391] *Id.* at lines 238-239.
[392] 2020 Protocol, Section 3.1.2.1.
[393] *S.C. Pub. Serv. Auth. v. Fed. Energy Regul. Comm'n*, 762 F.3d 41, 87-88 (D.C. Cir. 2014); *see also* Jonathan A. Lesser, Ph.D. & Leonardo R. Giacchino, Ph.D., FUNDAMENTALS OF ENERGY REGULATION at 183 (2d ed., Public Utilities Reports, Inc. 2013) ("One fundamental regulatory principle is to allocate costs to those who cause them.").

acquired in accordance with a State-Specific Initiative[.]"[394] The Protocol's cost allocation methodology demands that costs not be disconnected from benefits—and that the benefits are those that arise from use of the Resource in question.

As detailed above, the 2020 Protocol provides the State Resources category for identifying Resources that are attributable to state-specific electricity policy costs. If the Resource satisfies the criteria for State Resources acquired in accordance with programs that constitute State-Specific Initiatives, that appropriately results in situs assignment of those costs. Even in such cases, however, allocation and assignment of costs pursuant to the 2020 Protocol are not "isolated" from allocation and assignment of the benefits a state's customers receive from the Resource.

The Order contravenes the 2020 Protocol by enabling Utah customers to continue to benefit from Chehalis generation while disallowing costs required to provide it to them. This outcome is entirely at odds with the plain language of the 2020 Protocol and the cost-causation principle and should be reversed by the Commission.

iii. The Order Applies the 2020 Protocol in a Manner that Discriminates Against the Company as a Utility Providing Interstate Services.

In December 2023, the Company filed a complaint in federal district court in Tacoma, Washington, asserting claims regarding the constitutionality of certain provisions of the CCA under the dormant Commerce Clause of the U.S. Constitution.[395] In August 2024, the Company filed an appeal, which is still pending, in the U.S. Court of Appeals for the Ninth Circuit. Unless and until a court rules on the issues the Company has raised, it must comply with the law. The

[394] 2020 Protocol, Section 3.1.2.1.

[395] *PacifiCorp v. Watson*, Case No. 3:23-cv-6155, Complaint (W.D. Wash, Dec. 15, 2023). The U.S. District Court subsequently granted defendant's motion to dismiss for failure as a matter of law. *PacifiCorp v. Watson*, No. 3:23-cv-06155, 2024 WL 3415937, at *12 (W.D. Wash. July 15, 2024).

Company has also challenged the Oregon,[396] Wyoming,[397] and Idaho[398] state commission decisions that disallowed recovery of CCA costs attributable to Chehalis power used in those states.

Whatever the merits of dormant Commerce Clause challenges to the CCA, the Commission's application of the 2020 Protocol creates an outcome that itself is contrary to constitutional dormant Commerce Clause principles. The Commission's Order misapplies the neutral, non-discriminatory terms of the 2020 Protocol to create an outcome that, in practical effect, results in "purposeful discrimination against out-of-state economic interests."[399]

The Company's witnesses identified the ways in which CCA costs are similar to other inter-regional taxes and transfer costs resulting from other requirements like the Wyoming wind tax.[400] The Order denies the Company recovery of costs that are functionally the same as other state assessments that the Company is authorized to recover in its rates. The basis for the disparate treatment appears to be the Commission's determination that, due to its dissatisfaction with the way Washington's statute operates, certain interstate power transmitted from Washington will be treated differently than interstate power that the Company produces in the other states, including Utah.[401] The result of the Commission's decision is to protect Utah consumers from added costs

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[396] *See PacifiCorp v. Public Utility Commission of Oregon, et al.*, Oregon Court of Appeals, Case No. A183803.
[397] *See PacifiCorp d/b/a Rocky Mountain Power v. The Public Service Commission of Wyoming, et al.*, District Court of the First Judicial District, County of Laramie, State of Wyoming, Docket No. 2024-CV-0202385.
[398] *See PacifiCorp, d/b/a Rocky Mountain Power v. Idaho Public Utilities Commission*, Idaho Supreme Court, Case No. 52508-2024.
[399] *Nat'l Pork Producers Council v. Ross,* 598 U.S. 356, 371 (2023). The U.S. Supreme Court has overturned state administrative agency decisions, as well as state statutes and regulations, based on violations of the dormant Commerce Clause. *See, e.g., New England Power Co. v. New Hampshire,* 455 U.S. 331 (1982) (overturning an order of the New Hampshire Public Utilities Commission); *W. Lynn Creamery, Inc. v. Healy,* 512 U.S. 186 (1994) (invalidating a pricing order issued by the Massachusetts Department of Food and Agriculture). The 2020 Protocol is a cost allocation framework that was approved by order of the Commission, and the commissions in the other PacifiCorp states. *See* 2020 Protocol.
[400] Mitchell Direct at lines 361-363.
[401] *See RMP's Application for Approval of the 2024 EBA,* Docket No. 24-035-01, Order, Feb. 25, 2025, at 23-24 (The CCA "is a unique and discriminatory policy the State of Washington has engineered to impose its policy preferences on utilities' generation mixes while shifting the costs of those policy preferences to customers in other states.").

in their rates, while leaving the Company unable to recover approximately $19.4 million in legal compliance costs it cannot avoid. In this way, the Order, through its interpretation of the 2020 Protocol, converts the protocol from a reasonable cost allocation methodology into a means of discriminating against the Company as an interstate electric utility.

In the Commerce Clause context, "discrimination" means "differential treatment of in-state and out-of-state economic interests that benefits the former and burdens the latter."[402] A decision in 2023 summarized interstate commerce discrimination, overturning a Kentucky law favoring locally produced coal, noting that "[t]he real question . . . is not whether [the state law] *differentiates* between in-state and out-of-state coal but whether it *impermissibly* discriminates, as that term is used in the Commerce Clause. That is, does the law benefit in-staters and burden outsiders?"[403] Impermissible discrimination "is not limited to attempts to convey advantages on local merchants; it may include attempts to give local consumers an advantage over consumers in other States."[404]

This "antidiscrimination principle lies at the 'very core' of . . . dormant Commerce Clause jurisprudence."[405] Even if a state law, regulation, or order does not discriminate on its face, its "practical effects may also disclose the presence of a discriminatory purpose."[406] In examining state actions impacting interstate commerce, U.S. Supreme Court cases often find discriminatory practical effects in the cases of "state laws that impose burdens on the arteries of commerce, on trucks, trains, and the like."[407]

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[402] *Or. Waste Sys., Inc. v. Dep't of Env't Quality of Or.*, 511 U.S. 93, 99 (1994).
[403] *Foresight Coal Sales, LLC v. Chandler*, 60 F.4th 288, 297-98 (6th Cir. 2023).
[404] *Camps Newfound/Owatonna, Inc. v. Town of Harrison*, 520 U.S. 564, 577-78 (1997) (quoting *Brown-Forman Distillers Corp. v. New York State Liquor Auth.*, 476 U.S. 573, 580 (1986)).
[405] *Nat'l Pork Producers*, 598 U.S. at 371.
[406] *Id.* at 377.
[407] *Id.* at 392 (Sotomayor, J., concurring) (internal quotations omitted).

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Here, the Commission interprets the 2020 Protocol, which was approved by a Commission order, and which, on its face, is neutral and serves a legitimate purpose. The 2020 Protocol is, in fact, a methodology for managing the "arteries of commerce" among the states served by the Company.[408] The Commission's interpretation of the 2020 Protocol, however, results in discriminatory practical effects—allocating the benefits but not the costs of Chehalis power to Utah customers.

The misapplication of the 2020 Protocol gives Utah consumers an advantage to the detriment of the provision of interstate electricity by the Company. RMP is likely unable to recover the CCA costs for Chehalis power that is used to serve Utah from its Washington customers. Nevertheless, the Order disallows the Company's CCA costs when it sells Chehalis power in interstate commerce to Utah customers—sales that require the Company to incur the costs of securing CCA allowances.

The Company urges the Commission to reverse the Order as to the allocation of CCA costs and benefits because, as the Order stands today, it would not be in compliance with the dormant Commerce Clause. The Commission could achieve compliance by: (a) applying the neutral and non-discriminatory 2020 Protocol provisions as written and finding that Chehalis remains a "System Resource"; or (b) maintaining the Commission's position that Chehalis is a "State Resource," but removing the benefits of Chehalis from Utah rates.

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[408] *See NextEra Cap. Holdings, Inc. v. Lake*, 48 F.4th 306, 321-22 (5th Cir. 2022). (The "interstate grid [is] much closer to the heartland of interstate commerce than the wine stores, dairies, or waste processing facilities that have faced dormant Commerce Clause scrutiny. The Supreme Court recognized the interstate character of the electricity market a decade before it recognized that Congress could regulate factories because of their effect on interstate commerce." (internal citations omitted)).

iv. *The Order Harms the Company's Ability to Reach Its Authorized Rate of Return.*

The Company's 2020 general rate case set RMP's authorized overall rate of return at 7.34% and approved "a revenue requirement increase of $31.41 million."[409] By denying the Company recovery of all costs approved in the 2020 general rate case, which includes CCA costs, the Company will be harmed in its ability to reach its authorized rate of return. If RMP cannot reach its authorized rate of return, the Company will be denied the funds sufficient to satisfy what was ordered in the 2020 general rate case.

2. <u>If the Commission Will Not Reverse Its Disallowance of CCA Compliance Costs, It Should Revise the Order to Remove Chehalis Power from Utah Rates.</u>

If the Commission applies the 2020 Protocol according to its terms, Chehalis should be designated as a System Resource, with Utah paying its share of CCA compliance costs commensurate with its share of all other generation-related costs. Otherwise, the Commission shifts the costs of complying with the CCA statute to the Company, essentially creating a disallowance "for complying with Washington law," not because the Company engaged in imprudent activity.[410]

If the Commission will not reverse its determination regarding situs assignment of CCA compliance costs, the Company renews its request made in testimony that Utah customers forgo the benefits of Chehalis's generation.[411] This result is reasonable and consistent with governing law, if Utah customers do not pay compliance costs for Chehalis. Customers in the state of Utah cannot reap the benefits of Chehalis without paying their share of all of the costs the Company is

[409] *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. 20-035-04, Order, Dec. 20, 2020, at I ("Order of Dec. 20, 2020").
[410] Phase I Rebuttal Testimony of Joelle R. Steward at lines 917-918.
[411] *Id*. at lines 902-907.

forced to pay to provide those benefits. There is no dispute that the Company is forced to pay CCA compliance costs.

As it made clear in its testimony, the Company does not favor this outcome. It would increase Utah rates unnecessarily. It would also set "a poor precedent for other existing and future environmental compliance costs imposed by Utah or any other state on generating resources located in those states."[412]

That said, if the Commission remains determined to designate Chehalis CCA compliance costs as part of a State-Specific Initiative, the Commission should act consistently with the terms of the 2020 Protocol and remove both the costs *and* benefits of the Chehalis Resource from Utah rates. Otherwise, the Company will be required to subsidize Utah rates in a manner that is inconsistent with the approved cost allocation methodology and contrary to established ratemaking principles. Furthermore, the Order, if not corrected, would result in rates that are not just and reasonable.

F. The Order's Denial of Recovery of Annual Incentive Plan Costs Is Contrary to Prior Commission Rulings and Unsupported.

The Company's Annual Incentive Plan payments ("AIP") to non-union employees are just and reasonable expenses that the Company should be permitted to recover in customer rates. The Commission recognized as much in its 2020 GRC Order, but the Order in this proceeding departs from the Commission's prior determination despite no change to the Company's annual incentive plan and no new basis for the Commission to change its position on AIP. In this respect, the Order is flawed.

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[412] *Id*. at lines 935-937.

AIP is the "at risk" portion of overall market-rate employee compensation that is designed to incentivize employees to achieve objectives that directly benefit customers. As explained by Julie Lewis, Vice President of Human Resources for PacifiCorp, the incentive is designed to offer market average compensation, thus attracting qualified employees with the necessary skills to provide the important services offered by the Company.[413] Employees are eligible for AIP as the Company meets specific goals, which are tied to six core principles and as each employee meets or exceeds performance goals for their individual job.[414] This AIP is not a bonus. It is a portion of overall market-rate compensation that is only available if the employee and the Company meet specific goals, which incentivizes employees to perform at an exceptional level.[415] If AIP is not granted to an employee, that employee's pay is below market-rate and would result in the Company being unable to attract or retain employees who provide valuable services for customers.

As Ms. Lewis explained, there are six core principles against which an employee's performance is assessed to determine whether that employee should receive AIP and, if so, to what extent.[416] Only one of those core principles directly relates to financial performance and, even then, the focus is on maintaining strong credit ratings, a high-quality and diversified portfolio of regulated businesses, and a financially healthy and well-capitalized utility, all of which benefit customers.[417]

As testified to by Ms. Lewis in this proceeding, the Company's AIP plan has not changed since the 2020 GRC.[418] And the Commission approved 100 percent of the Company's requested

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[413] Phase I Surrebuttal Testimony of Julie Lewis at lines 11-13 ("Lewis Surrebuttal").
[414] *See* Phase I Rebuttal Testimony of Julie Lewis at lines 41-47 ("Lewis Rebuttal").
[415] *Id*. at lines 94-98.
[416] *Id.* at lines 50-52.
[417] *Id.* at lines 139-141.
[418] *Id*. at lines 163-164.

compensation program in 2020.[419] With that approval, the Commission acknowledged that market-rate compensation is in the public interest and customers could be harmed if Company employees lacked needed skillsets.[420] Specifically, reviewing precisely the same plan and AIP structure that is in place in this case, the Commission stated:

> Consistent with that decision, we find the record in this docket establishes that the six incentive goal categories predominantly benefit customers. Regardless of RMP's internal incentive plan structure, we find that the evidence supports RMP's contention that aggregate employee base pay plus all available incentive awards generally reflect the average market rate. We conclude that it is prudent for RMP to pay its employees awards related to the incentive components that were presented in evidence. This avoids potential harm to customers that could occur if total compensation less than the market rate resulted in RMP's employees lacking necessary and appropriate skills. Accordingly, we decline to make the requested adjustment to RMP's revenue requirement.[421]

Notwithstanding that prior ruling and the fact that the Company's plan and AIP structure has not changed, the Commission, in the Order, concluded:

> We find . . . it is neither just nor reasonable for ratepayers to bear the cost of AIP compensation directed to incentivizing achievement of financial objections that primarily serve the interest of RMP's parent company and its shareholders. RMP's argument that denial of those costs will result in under-market compensation can only be true to the extent shareholders are unwilling to reward employees for achieving financial targets that benefit them. In either case, we decline to shift those costs to ratepayers. To allow RMP to include the recovery of AIP costs tied to its financial goals results in customers payments these compensation costs whether financial goals are achieved or not. Shareholders, on the other hand, who ultimately benefit from these financial goals, would be insulated from the risk of financial goals not being achieved. We therefore adopt FEA's recommendation of an adjustment in RMP's Test Year revenue requirement by $2,880,622.[422]

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[419] *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. 20-035-04, Order at 28-29 (Dec. 30, 2020).
[420] *Id.*
[421] *Id.* at 28.
[422] Order at 80.

This conclusion is erroneous for several reasons.

First, the Commission determined in 2020 that the very same plan and AIP structure at issue in this case *primarily benefitted customers* (not shareholders), even though the achievement of financial goals is a component of the core principles of the plan. The Commission provides no basis in the Order to find that the same plan and AIP now primarily benefit RMP's parent company and its shareholders, as the Commission claims. Furthermore, intervenors made the very same arguments and submitted the same kind of evidence here that the Commission considered and rejected in concluding in 2020 that it was just and reasonable for AIP to be included in customer rates.

Second, RMP provided evidence here (as it did in 2020) demonstrating that AIP is not a bonus and, even when paid, reflects only the average market compensation any entity would have to pay in the industry to maintain such employees. No party submitted any evidence to the contrary. On that same evidence, the Commission determined in 2020 that there would be "potential harm to customers" if total compensation was below market and, on that basis, determined that including AIP in rates was appropriate to ensure that customers are served by a Company with qualified employees. But here, the Commission states, in a conclusory manner, that shareholders should bear the burden of ensuring that employees receive market compensation by absorbing the full cost of AIP. But the Commission provides no rationale for arriving at the opposite conclusion from what it determined in 2020. As such, the Order's AIP determination simply appears to be an attempt by the Commission to shift costs that should be included by rates exclusively to shareholders, which is not appropriate.

Finally, even if there were a basis to justify the Commission's conclusion on AIP, by adopting the FEA's position, the Order overstates any adjustment. As Ms. Lewis pointed out in her pre-filed rebuttal testimony, because Mr. Gorman's FEA adjustment removes the full financial weighting for each year's scorecard, his adjustment "results in the removal of certain financial goals even in periods where those financial goals were not achieved."[423] Thus, his adjustment removes the financial portion of AIP twice.[424] The Commission offers no basis to justify such a removal that is inconsistent with their reasoning.

G. The Order Employed an Incorrect Standard and Ignored Company Evidence In Reducing the Company's Recovery of Legal and Expert Expenses.

The Commission's ruling on the Company's proposed legal and expert expenses demonstrates that the Commission applied an incorrect standard for setting those costs and employed an incorrect prudence standard. First, the objective of setting test period costs is not to establish what may have been historically typical for a cost category. Rather, it is to estimate what those costs will be during the rate-effective period to set just and reasonable rates: "The purpose of a test year, or test period, is to provide revenue, expense, and investment information that reasonably approximates circumstances expected during the period rates will be in effect."[425] Despite this, the Commission's decision refuses to accept the Company's estimates for those expenses, concluding that RMP's 2023 legal and expert expenses, on which its test-period costs were based, were "anomalous."[426] But this conclusion entirely ignores how these types of expenses have been estimated in prior cases (and approved by the Commission) as well as the evidence provided by the Company.

By using 2023 actual costs to forecast expected legal and expert expenses during the test period, the Company followed the well-established approach that has been used in prior rate cases

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[423] Lewis Rebuttal at lines 169-172.
[424] *Id.* at lines 174-175.
[425] Order, *Re Mountain Fuel Supply Company,* Docket No. 89-057-15 at (Nov. 21, 1990).
[426] Order at 85.

and approved by this Commission. As Ms. McCoy explained during the hearing, the Company's approach is "[c]onsistent with past practice to estimate costs that are difficult to forecast and increasing in nature."[427] Further, as the Order notes, "neither OCS nor DPU presented an alternative methodology to forecast 2025 Test Year Legal and other expert expenses."[428] Instead, their proposed adjustments were arbitrary and based on past information that is not relevant to the legal and expert expenses the Company will incur during the rate-effective period.

The Company used 2023 actual costs for its 2025 test period costs because those costs are the most current and are reflective of existing litigation and expert expenses for ongoing legal matters, some of which will continue into the rate-effective period. As Ms. McCoy explained:

> [L]ooking at legal expenses since 2020, the Company has experienced a dramatic uptick each and every year and that trend appears to be one that is likely to continue into the Test Year. While the individual legal matters may be different in 2025 than those experienced in 2023, the activity will likely continue. . . . The use of the Base Period is [the] only [ ] prudent way to estimate the level of future Test Year expense. Adopting the proposed adjustments to legal expenses would leave in the Test Year an amount that is less than the actual legal expenses incurred in 2021, 2022, and 2023.[429]

Further, Ms. McCoy showed that the first three quarters of 2024 were actually higher than the legal and expert expenses in 2023, demonstrating that the Base Period amounts are not only not anomalous, but may understate what the Company will actually incur. No party disputed that the Company's legal expenses have steadily risen since 2020 and continued to increase into 2024, and this evidence from Ms. McCoy shows that 2023's amounts are likely to be more accurate for the test period than the amounts from prior periods. By contrast, the Order's adjusted amount is not only not reflective of the steady increase in these costs since 2020, but is below the amounts the

[427] Hr'g Tr. 932:7-8 (Dec. 12, 2024).
[428] Order at 85.
[429] Phase I Rebuttal Testimony of Shelley E. McCoy at lines 818-827 ("McCoy Rebuttal").

Company was incurring even in prior years. There is no factual basis to support such a reduction, and 2023 costs are clearly not anomalous where they follow a consistent pattern of increasing legal and expert costs over each of the four years since 2020.

The Order suggests that the Company's evidence was flawed because Ms. McCoy did not have the legal invoices for 2023 available and was unable to identify specific cost items that were included in the 2023 figures.[430] But such a showing has never previously been requested, let alone required, by the Commission during any prior rate case, nor did the other parties claim the Company's legal and expert costs were not expended in legal matters in which the Company was involved during 2023. The evidence Ms. McCoy provided is the same type of evidence the Company has provided, which has been found to be adequate by this Commission in prior rate cases. Simply stated, the Order departs from the Commission-approved approach and does so without substantial evidence.

In addition, the Commission's assertion that "RMP has not presented remotely sufficient evidence to demonstrate that such expenditures are prudent and recoverable from Utah ratepayers" is both inexplicable and reliant on an incorrect prudence standard.[431] To the extent the Commission's statement is a reflection of its claim that the Company's legal and expert expenses should be reduced because those costs are associated with the *James* verdict or alleged negligence on the part of the Company, that statement constitutes error twice over. As addressed above, the Company was not at fault for the fires at issue in *James* as has now been confirmed by a years-long government investigation. Furthermore, the legal and expert expenses at issue in the test-period amounts are not reflective of those costs. As Ms. McCoy explained: "Regarding the premise

[430] Order at 84-85.
[431] *Id.* at 85.

of negligence, the Company is not seeking recovery of any specific legal expense in this case. The legal expenses incurred in the 2023 Base Period have already been incurred."[432] In other words, while the 2023 costs that were used to forecast future costs did include legal costs related to wildfire litigation, the anticipated costs during the rate-effective period are not seeking to recover 2023 costs. Rather, those amounts are used to estimate future expenses throughout its service area, which are expected to increase as they have been consistently doing for four years.[433] Thus, 2023 costs provide the most accurate proxy for the test period amount.

Also, to the extent the Commission's ruling on these costs is an attempt to remove *all* wildfire-related litigation and legal costs,[434] the ruling is unfair and improper. The legal and expert expenses included in the Company's revenue requirement are for future legal and expert expenses, and there has been no showing by any party that those costs are improper or imprudent in any way. The Company is not seeking to recover costs incurred in the *James* case here. Thus, by trying to limit test-period legal and expert costs on the basis of *James,* the Order is engaging in impermissible retroactive ratemaking for costs that have already been spent and for which recovery is not being sought in this proceeding.

Finally, to the extent the Commission's ruling is based on the assertion that Utah ratepayers should not share in system-wide litigation costs, the decision is unfair and inconsistent with this Commission's prior rate case rulings. As Ms. McCoy explained, the Company's approach to forecasting legal expenses "does not seek recovery of specific legal activities, but rather establishes a level of expense that is reasonably expected to be incurred in the Test Year."[435] Utah customers benefit from the Company's facilities in various states, and these facilities are currently included

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[432] McCoy Rebuttal at lines 821-823.
[433] *See* McCoy Rebuttal at lines 772-775.
[434] *See* Phase I Surrebuttal Testimony of Donna Ramas at lines 733-735 ("Ramas Surrebuttal").
[435] Phase I Surrebuttal Testimony of Shelley E. McCoy at lines 99-101 ("McCoy Surrebuttal.")

in Utah rates. It is not even-handed for the Commission to allow Utah customers to receive the benefits from those facilities without also recognizing that the Company will inevitably incur expenses associated with those facilities, including legal and expert expenses.

H. The Commission's Decision to Reduce the Company's Recoverable Injury and Damages Costs Wrongly Fails to Follow Commission Precedent, Incorrectly Assumes Negligence by the Company, and Ignores Evidence Supporting Those Costs.

In 2007, the Commission established the methodology the Company is required to use for setting the amount of injury and damages expenses in its revenue requirement.[436] That methodology—using the three-year historical average using the cash method—has been followed ever since, and the Company's revenue requirement in this docket follows that same methodology here. However, the Commission's Order departs from that approach. Its justification for doing so is its conclusion that it "cannot find RMP has provided substantial evidence that its projected Test Year ID Expenses reasonably estimate expenses it is likely to incur in the Test Year, given the significant anomalies in recent years."[437] The Commission does not identify the "anomalies" to which it refers. The Commission also notes that "the Test Year projection is heavily influenced by payments made to settle wildfire claims where serious questions exist as to whether RMP's tortious conduct has given rise to the significant increase in claims against it."[438] With no further basis, the Commission denied the Company's proposed Test Period ID expenses and, instead, ordered the Company's recovery to be limited to the Test Period ID expense from the 2020 GRC Order, even though those amounts have no relationship whatsoever to this case and would have been based on

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[436] *See* Report and Order on Revenue Requirement, *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, at 76 (Aug. 11, 2008) ("2008 Report and Order").
[437] Order at 88.
[438] *Id.*

the three-year average of ID expenses from periods dating back to 2016—nearly 10 years from the test period in this case.[439]

Similar to so many of the Commission's rulings, its determination of Test Period ID expenses departs from long-standing precedent, ignores the Company's evidence, and wrongfully bases its determination on the Company's alleged negligence, which ODF's report has now undermined. The whole reason the Commission ordered the usage of a three-year average to set test period ID expenses in a revenue requirement was because it is difficult to predict what future ID expenses will be:

> [D]ue to the uncertain nature of, and difficulty in, predicting this type of expense we conclude the Committee's proposal to use an average of historical expenses is more appropriate for utility rate making. This is supported by testimony that an actual expense may lag a claim by six or more years. The Committee's proposal will ensure timely recovery of this type of expense for the Company, provide simplicity in determining the forecast and is consistent with averaging already undertaken for other accounts.[440]

In the face of the reasoning underlying the establishing of this three-year methodology, the Commission statement that it "cannot find RMP provided substantial evidence that its projected Test Year ID Expenses reasonably estimate expenses it will likely incur in the Test Year" is particularly inexplicable. The Company used the three-year average expense amounts precisely *because that is the approach ordered by the Commission* that was to be used. The Company provided the evidence it was required to provide and has been providing in every general rate case since 2007, which has always previously been accepted by the Commission.

Furthermore, current ID expenses are more likely to provide a more accurate basis to estimate Test Year ID expenses because they are reflective of recent and ongoing events, some of

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[439] *Id.*
[440] *See* 2008 Report and Order at 75-76.

which may continue into the rate-effective period. That is precisely what the Company provided. Furthermore, as Ms. McCoy explained, the ID expenses included by the Company are based on actual, historical claim data, which all parties had available for audit, and that information shows the recurring nature of the costs over a multi-year period, undermining the suggestion that the costs are somehow anomalous.[441] To the extent the Commission views the expenses as extraordinary due to fire-related damages, this is an improper basis for assessment. The average that has been used since 2007 always incorporates expenses associated with such events, including damages arising out of fire-related events and including self-retention insurance amounts.[442]

Finally, for the reasons explained at length above, it is improper for the Commission to reduce the Company's recovery of ID expenses on the basis of the Company's alleged negligence associated with the *James* case. The Company has been deemed not at fault for the catastrophic damage associated with at least one of those fires, and the Company is appealing the verdict overall. As such, there are not "serious questions" about "whether RMP's tortious conduct has given rise to the significant increase in claims against it," as the Commission claims. While the Company was sued in connection with the Oregon wildfires, the ODF has now determined that the Company's actions were not the cause of the fire with the largest amount of damage. Further, it is improper for the Commission to not allow the Company to reflect ID expenses associated with wildfire claims in the historical average. ID expenses are a normal and expected cost of doing business, and the Commission has not previously denied recovery of such costs on the basis that they are associated with the resolution of lawsuits.

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[441] McCoy Rebuttal Testimony at lines 1233-1237.
[442] *Id.* at lines 1262-1265.

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I. The Commission's Interpretation of the KHSA and 2012 Settlement Stipulation Is Incorrect, and Disallowance of the Fall Creek Hatchery Costs Would Provide a Windfall as Utah Customers Have Received the Benefits of the Hatchery Without Paying Any Amount for It.

As part of this general rate case, the Company proposed to recover funds for the construction and operation of the Fall Creek Hatchery. Contrary to the Commission's Order, cost recovery from Utah ratepayers for this project is reasonable and justified. First, as discussed below, the Klamath Hydroelectric Settlement Agreement ("KHSA") and the 2012 Settlement Stipulation support recovery. Second, Utah customers have received benefits from the hatchery and, as such, it is reasonable for Utah customers to pay a share of the associated costs.

In the Order, the Commission denied the Company recovery of the Fall Creek Hatchery costs on the following basis:

> We conclude the basic intent of the 2012 GRC Settlement is clear: Utah ratepayers are not responsible for the costs RMP incurs to fulfill its obligations under the KHSA save for those costs that are expressly identified or are generally related to generation. We further find it is not just or reasonable to require Utah ratepayers to fund a plurality of the costs RMP incurs to construct and operate a fish hatchery in another state for the purpose of fulfilling RMP's obligations to California and Oregon under the KHSA. We approve UAE's recommended adjustment and deny the $2,495,883 in revenue requirement that RMP seeks relating to the Fall Creek Hatchery.[443]

This interpretation by the Commission is legally flawed, and the Commission's decision would require the Company to provide Utah customers with benefits for which they have not paid, which is contrary to long-standing regulatory principles.

First, the KHSA was entered into by PacifiCorp and stakeholders, including California and Oregon state agencies, for the removal of the Klamath dams. As part of the KHSA, the Company

[443] Order at 68.

agreed to perform a number of actions unrelated to the dam removal, referred to as "the Interim Measures." The relevant Interim Measures in this proceeding are contained in Appendix D of the KHSA and were designed to provide a suite of environmental actions to allow continued operation of the Klamath dams to provide low-cost hydroelectric energy to customers.[444] The nature of the Interim Measures is referred to in Section 6.1.2, Duty to Support, of the KHSA, which provides that "… each Party shall support the Interim Measures set forth in appendices C and D, and will not advocate additional or alternative measures for the *protection of environmental resources* affected by the Project during the Interim Period."[445] No party disputes the prudency or need for the Interim Measures, which included the construction of the Fall Creek Hatchery.[446]

To address KHSA implementation issues unrelated to cost recovery for Interim Measures, the Company entered into the 2012 Settlement Stipulation, which was addressed by this Commission in Docket No. 11-035-200. In the present proceeding, UAE advocated (and the Commission adopted the view) that the Fall Creek Hatchery project is a dam removal cost that is not recoverable from Utah customers, even if it were an "Interim Measure."[447] This is fundamentally incorrect and demonstrates a misunderstanding of the 2012 Settlement Stipulation. As described by Company witness Timothy J. Hemstreet, who has been involved with Klamath since 2006 and helped draft the KHSA and Stipulation:[448] "The 2012 Settlement Stipulation provision cited by Mr. Higgins was never intended to resolve questions of whether, or in which cases, the Company could seek cost recovery for its expenditures to implement Interim Measures in fulfillment of its obligations under the KHSA. This is clear since the word "Interim Measures"

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[444] *See* UAE Exhibit RR 1.20 and Hr'g Tr. 770:9-15 (Dec.11, 2024).
[445] UAE Exhibit RR 1.20 at 27 (emphasis added). "Project" refers to the Klamath Hydroelectric Project licensed by FERC under Project No. 2082. UAE Exhibit RR 1.20 at 6.
[446] Hr'g Tr. 766:21-767:1 (Dec. 11, 2024).
[447] Higgins Surrebuttal at lines 604-06; Order at 67.
[448] Hr'g Tr. 772:22-773:6 (Dec.11, 2024).

fails to appear in the stipulation."[449] Indeed, the construction and funding of the Fall Creek Hatchery "is neither a dam removal cost as understood in the 2012 Settlement Stipulation or a dam removal cost under a correct understanding of the KHSA."[450]

UAE witness Higgins relied on paragraph 60 of the Stipulation to support his argument that the Stipulation precludes cost recovery for the Fall Creek Hatchery project, and the Commission apparently also adopted that view. That interpretation is incorrect and misunderstands the KHSA, the Stipulation, and Docket 11-035-200. As Mr. Hemstreet testified at hearing:

> . . . UAE's proposed adjustment ignores the intent of the 2012 settlement stipulation, which was to narrowly resolve issues of, one, whether Utah customers should be allocated a portion of facilities' removal costs; two, cost recovery of Klamath licensing and settlement process costs; and, three, accelerated depreciation of the facilities on a schedule consistent with the KHSA's dam removal time line.
>
> Further, a review of the record in the 2012 general rate case makes it clear that the 2012 settlement stipulation was never intended to address cost recovery for interim measures implemented by the Company pursuant to the KHSA. In fact, in the 2012 general rate case, the Company sought cost recovery for study costs related to Interim Measure 19, *and no party in that case, including UAE*, opposed cost recovery for the study that ultimately resulted in the construction of the Fall Creek Hatchery. Therefore, the 2012 settlement stipulation was not considered to have a bearing on Interim Measure cost in 2012 and thus clearly has no bearing on the consideration of cost recovery in this proceeding.
>
> The 2012 settlement stipulation provision used by UAE to support its argument was solely intended to clarify that the 172 million customer contribution under the KHSA towards the defined scope of facilities removal could not be allocated to Utah customers, as had been proposed in the case by the Company. If the 2012 settlement stipulation had been intended to mean what UAE argues, it would have clearly expressed the cost recovery prohibition for

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449 Phase I Rebuttal Testimony of Timothy J. Hemstreet at lines 70-74 ("Hemstreet Rebuttal").
450 *Id*. at lines 45-48.

> KHSA interim measures, the only significant expenditures implemented by the Company under the KHSA.[451]

This issue can be settled by a correct interpretation of paragraph 60 of the 2012 Settlement Stipulation. UAE divided paragraph 60 into "part one where PacifiCorp is not permitted to recover" and "part two where PacifiCorp may request recovery."[452] UAE attempts to insert its own definition into paragraph 60 to show that "removal costs or removal related costs" includes Hatchery *construction costs*. But paragraph 60, which provides a list of defined terms for which the Company cannot recover, specifically applies to facilities removal for the Klamath *dams*. In fact, the definition of "Facilities Removal" in the KHSA and Section 7.2.2, Detailed Plan for Facilities Removal, of the KHSA contains no cross-reference to the Interim Measures.[453] Taken to its illogical conclusion, UAE's argument would make any action associated in any way with the KHSA facilities removal-related as that is the subject of the KHSA.

Additionally, nowhere in paragraph 60 do the words "interim measures" appear. At hearing, Mr. Hemstreet, who helped draft the Stipulation, testified:

> You know, if that was our understanding [that facilities removal meant interim measures], we probably would have, you know, put interim measures in there as one of the specific things that we will seek cost recovery for because at the time we were simply addressing the $172 million facilities removal cost. So it was not in anybody's mind, nor my mind, at the time that anybody would interpret that to mean that we would not seek cost recovery for interim measures because we had—you know, in that proceeding we had discussed here's what the Company's going to pay in the settlement, and interim measures *were part of that*.[454]

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[451] Hr'g Tr. 767:14-768:21 (Dec. 11, 2024) (emphasis added).
[452] *Id.* at 790:5-9.
[453] UAE Exhibit RR 1.20 and Hr'g Tr. 774:13-775:13; 796:20-797:16. (Dec.11, 2024).
[454] Hr'g Tr. 790:24-791:10 (Dec. 11, 2024) (emphasis added).

Thus, a review of the record in the 2012 general rate case and a correct understanding of the KHSA and the 2012 Settlement Stipulation shows that Interim Measures were not intended to be precluded by the 2012 Settlement Stipulation, and the Company is allowed to recover its prudently incurred costs related to the construction and operation of the Fall Creek Hatchery.

Additionally, had the hatchery not been constructed, the Company would not have been able to continue receiving low-cost hydroelectric power between the time the KHSA was executed and the time the dams were actually removed. It was, after all, because of the Company's commitment to continued hatch reproduction that there was an agreement to allow the dams to continue generating power, allowing the Klamath assets to generate significant benefits for Utah customers.[455] Thus, there is no dispute that Utah customers benefitted from the hatchery because they received power from the dam facilities. In fact, Utah customers have "benefited from 18 years of low cost energy after the FERC license for the Klamath project expired in 2006."[456] Further, Utah ratepayers have been "shielded . . . from being assessed any of the $450 million in funding needed to implement the dam removal project."[457] These benefits alone justify including costs associated with the Fall Creek Hatchery in Utah rates, consistent with the basic regulatory principles of cost-causation and the matching principle, as Utah customers are receiving the benefits that flow from the Fall Creek Hatchery.

Finally, even under the Commission's interpretation of the 2012 Settlement Agreement, the construction of the Fall Creek Hatchery should be allowed into rates because the subject costs were incurred to provide continued generation from the Klamath dams as the hatchery started operations in November 2023 before the dam ceased operations in January 2024.[458]

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455 *Id.* at 770:23-771:6
456 *Id.*
457 *Id.* at 771:7-12.
458 *Id.* at 801:5-14. However, the official "in service" date reflects when the accounting was closed in March 2024.

J. The Final Order Does Not Comply with Utah Code § 54-7-12 and Should Be Set Aside, and the Company's Proposed Rate Increase Should Be Deemed Final.

The Supreme Court of Utah has long made clear that "the PSC has only the rights and powers granted to it by statute."[459] "It is well established that the Commission has no inherent regulatory powers other than those expressly granted or clearly implied by statute."[460] Utah courts have, in fact, stated that, despite the broad language of Utah Code § 54-4-1, that provision "does not confer upon the Commission a limitless right to act as it sees fit, and [the] court has never interpreted it as doing so. 'Explicit or clearly implied statutory authority *for any regulatory action* must exist.'"[461] As such, unless a statute vests the Commission with the authority and power to take an action, the Commission cannot assume the right to exercise such authority or power. The Order runs afoul of these principles.

Utah Code § 54-7-12 governs the content of a rate case filing, the manner in which that filing must be addressed by the Commission, and, most importantly, the scope of actions the Commission is permitted and required to take relative to that filing. Specifically, under that provision, once a general rate case filing is deemed complete, the Commission must, within 240 days, hold a hearing on that filing and "shall issue a final order" adopting one of three exclusive options: "(i) grant the proposed general rate increase or decrease; (ii) grant a different general rate increase or decrease; or (iii) deny the proposed general rate increase or decrease."[462] If the Commission does not issue a final order "within 240 days after the public utility submits a complete filing in accordance with Subsection (3)(a): (i) the public utility's proposed rate increase

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[459] *Hi-Country Ests. Homeowners Ass'n v. Bagley & Co.*, 901 P.2d 1017, 1021 (Utah 1995).
[460] *Mountain States Tel. & Tel. Co. v. Public Serv. Comm'n*, 754 P.2d 928, 930 (Utah 1988).
[461] *Hi-Country Ests. Homeowners Ass'n*, 901 P.2d at 1021 (internal citations omitted, quoting *Mountain States Tel & Tel. Co.*, 754 P.2d at 930) (emphasis added).
[462] Utah Code § 54-7-12(2)(c), (3)(a) (emphasis added).

or decrease is final; and (ii) the commission may not order a refund of any amount already collected or returned by the public utility under Subsection (3)(a)."[463]

Under § 54-7-12, a general rate case filing is a "complete filing" if the utility "substantially complies with minimum filing requirements established by the commission, by rule, for a general rate increase or decrease."[464] A utility's filing is deemed a "complete filing" "unless within 30 days after the day on which the commission receives the public utility's application, the commission issues an order describing information that the public utility must provide for the application to be considered a complete filing."[465] The Commission has also promulgated extensive rules for what must be included in a rate case filing for it to be deemed complete and to provide adequate information for those participating in the rate case.[466]

In this docket, the Company's Application was a "complete filing," as more than 30 days passed without the Commission declaring any aspect of that filing incomplete. Further, when the Company filed its Amendment to the Application, neither the Commission nor any party claimed that the Amendment to the Application constituted a new rate case filing or restarted the 240-day deadline. In fact, the Commission acknowledged that the Amendment to the Application did not change the deadline by which it was obligated to issue a final order in this docket. In its October 4, 2024 Order, the Commission made the following statement:

> Pursuant to Utah Code § 54-7-12(3)(a), the PSC must issue an order within 240 days of RMP submitting a complete filing. RMP filed its initial application and supporting materials on Friday, June 28, 2024, 240 days from which is Sunday, February 23, 2025. Accordingly, the PSC must issue an order by Friday, February 2[3], 2025, to comply with the statute. The PSC notes RMP submitted an amended application on August 28, 2024, which could be argued to restart the 240-day statutory timeframe. However, *no party has*

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463 Section 54-7-12(3)(b).
464 Section 54-7-12(1)(b).
465 Section 54-7-12(2)(b)(i).
466 Utah Admin. Rules, R746-700-1 *et seq*.

requested the PSC alter the existing schedule, and, at present, the PSC is proceeding with the intention of complying with the February 2[3], 2025, deadline.[467]

There is no language in § 54-7-12(3) (or any other statutory provision) that allows the Commission, in a general rate case setting, to issue a decision that is different from the three options provided for in § 54-7-12(3)(a).[468] Rather, that provision is exclusive and states that the Commission "shall" undertake one of the three specified actions within 240 days after the filing is deemed complete. The exclusive nature of the listed actions, the use of the term "or" between those alternatives, and the lack of any language vesting the Commission with discretion to pursue other alternatives clearly indicates that the Commission lacks authority to pursue another course of its own choosing outside the statutory list.[469] For example, there is no language that would allow the Commission, for example, to (i) delay a decision on some or all aspects of a complete filing, (ii)

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[467] *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*, Order, Docket No. 24-035-04, at 14 n. 26 (Oct. 4, 2024) (emphasis added).

[468] *Provo City Corp. v. Willden*, 768 P.2d 455, 458 (Utah 1989) ("[I]n seeking a constitutional construction, we will not rewrite a statute or ignore its plain intent. 'A fundamental principle of statutory construction is that unambiguous language in the statute itself may not be interpreted so as to contradict its plain meaning.'") (quoting *Johnson v. Utah State Ret. Bd.*, 770 P.2d 93, 95 (Utah 1988)) (internal citations omitted); *Mountain States Tel. & Tel. Co. v. Pub. Serv. Comm'n*, 155 P.2d 184, 185 (Utah 1945) ("We therefore address ourselves to its meaning, keeping in mind one of the cardinal rules of statutory construction, viz., that the interpretation must be based on the language used, and that the court has no power to rewrite a statute to make it conform to an intention not expressed. 'The legislative intent being plainly expressed, so that the act read by itself, or in connection with other statutes pertaining to the same subject, is clear, certain and unambiguous, the courts have only the simple and obvious duty to enforce the law according to its terms.'") (internal citations omitted).

[469] *See, e.g.*, *McKitrick v. Gibson*, 496 P.3d 147, 155 (Utah 2021) (interpreting Utah Code § 63G-2-701(6)(a)(ii) and holding that, under the doctrine of *expressio unius,* the statute was intended to give a limited method of appealing: "we assume that the legislature used 'requester' and 'political subdivision' advisedly in crafting GRAMA's appellate review language, and to the exclusion of other persons or entities that might have an interest in appealing a local review board's access decision. . . . *There is no textual suggestion that the terms 'political subdivision' and 'requester' are meant to be merely illustrative or otherwise non-exclusive*.") (emphasis added); *Nevares v. M.L.S.*, 345 P.3d 719, 725-26 (Utah 2015) ("That implication follows from established canons of statutory construction. One such canon is the expressio unius principle of interpretation—the notion that the statutory expression of one term or limitation is understood as an exclusion of others. Section 111 articulates a single limitation on the proof of "conduct" constituting a criminal "offense": Such proof does not require a "formal [ ] charge[ ]" or "convict[ion]." And under the expressio unius canon, *the expression of that limitation is an implied rejection of others*.") (internal citations omitted) (emphasis added).

declare that an amendment to an application restarts the 240-day deadline, or (iii) extend the date for the issuance of a final order.

While the Company understands that the Commission's position that it has the authority to declare that the 240-day deadline restarted when the Company filed its Amendment to the Application, that position finds no statutory support in § 54-7-12 or any case law. The Legislature would not have provided that the Commission "shall" enter a final order on a "complete filing" within 240 days if the Commission were permitted to unilaterally declare that a filing by the Company restarted or extended that deadline. Such an approach would defeat the structure and purpose of § 54-7-12. Further, if the Legislature intended the deadline to be restarted by an amendment to an application, the statute would include language reflecting that intent. It does not. In fact, it states just the opposite—that once a general rate case filing is a complete filing, the 240-day deadline begins to run with no provision for that deadline to restart.

The Company reminded the Commission of the 240-day deadline and its implications repeatedly throughout this docket and encouraged the Commission to conduct the proceedings such that it would be able to issue a final order by the 240-day deadline. Despite that, the Commission concluded that it was not required to issue a final order by the 240-day deadline. The Commission, nevertheless, purported to enter a final order on February 20, 2025, presumably out of concern about the deadline, but that order was not a final order, as addressed by the Company in a separate filing. A final order on a rate case application is one that fully and finally resolves all rate issues raised. Here, the Commission did not issue a final order by the 240-day deadline. In fact, the submission of testimony and hearings were still taking place a month after that deadline came and went. Instead, the Order was not issued until April 25, 2025, two months after the statutory deadline had run. As a result, the Order does not comply with Utah Code § 54-7-12, and the Company's Application, as amended by its Amendment, should be deemed final under Utah Code § 54-7-12(3)(b)(1).

V. CONCLUSION

For the foregoing reasons, the Company respectfully requests that the Commission grant review of the Order, and revise it consistent with the above, or, alternatively, grant rehearing of the issues set forth above.

Respectfully submitted this 27th day of May 2025.

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CERTIFICATE OF SERVICE

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