Decision No. C23-0592

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 22AL-0530E

IN THE MATTER OF ADVICE LETTER NO. 1906 - ELECTRIC FILED BY PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO P.U.C. NO. 8 - ELECTRIC TARIFF TO INCREASE BASE RATE REVENUES, IMPLEMENT NEW BASE RATES FOR ALL ELECTRIC RATE SCHEDULES, AND MAKE OTHER TARIFF CHANGES, TO BECOME EFFECTIVE DECEMBER 31, 2022.

PROCEEDING NO. 22AL-0478E

IN THE MATTER OF ADVICE LETTER NO. 1902 - ELECTRIC FILED BY PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO P.U.C. NO. 8 - ELECTRIC TARIFF TO INCREASE THE TRANSMISSION COST ADJUSTMENT RIDER, TO BECOME EFFECTIVE JANUARY 1, 2023.

COMMISSION DECISION APPROVING SETTLEMENT AGREEMENT WITH MODIFICATIONS, PERMANENTLY SUSUPENDING TARIFFS, ESTABLISHING RATES, AND REQUIRING COMPLIANCE FILINGS

Mailed Date: September 6, 2023
Adopted Date: August 16, 2023 and September 6, 2023

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I. BY THE COMMISSION

A. Statement

1. By this Decision, the Commission approves the Settlement Agreement filed on June 20, 2023, between Public Service Company of Colorado (Public Service or the Company) and intervenors Staff of the Colorado Public Utilities Commission (Trial Staff); the Colorado Office of the Utility Consumer Advocate (UCA); Colorado Energy Consumers (CEC); the Colorado Energy Office (CEO); Molson Coors Beverage Company (Molson Coors); Federal Executive Agencies (FEA); and Walmart Inc. (Walmart) (collectively, the Settling Parties) as part of a comprehensive package that also modifies the Transmission Cost Adjustment (TCA). A copy of the Settlement Agreement is attached to this Decision as Appendix A.

2. By approving the revenue requirement portions of the Settlement Agreement as part of a larger package, this Decision establishes new base rates for Public Service. The Commission authorizes Public Service to increase its base rate revenues through a modified General Rate Schedule Adjustment (GRSA), for incremental base rate cost recovery on an energy basis from residential and small commercial rate classes, or through a combination of a traditional GRSA, expressed as a percentage increase to all existing base rate components, and a General Rate Schedule Adjustment-Energy (GRSA-E), expressed on an energy basis, for incremental base rate

cost recovery from all other customer rate classes. The increase in base rate revenues shall be the net of the transfer of certain costs recovered through separate rate adjustment mechanisms.

3. The Settlement Agreement resolves all issues that have been or could have been raised in this Proceeding, except for two: a proposal to defer costs, generally depreciation expenses, associated with Public Service's coal-fired electric generation facilities scheduled for retirement (Coal Plant Deferral), and a proposal to adjust Public Service's TCA for effect beginning January 1, 2024.

4. In accordance with the discussion below, the Commission finds the record does not support approval of the Coal Plant Deferral. The Commission further finds good cause to adjust the scope of projects eligible for recovery through the Company's TCA as part of a balanced package that also includes the approval of the revenue requirement portions of the Settlement Agreement. Accordingly, the Commission modifies Sheet 142B of Public Service's Colorado Electric Tariff No. 8 to include a definition of "TCA Qualified Projects" as transmission investment that results in a net increase in transmission capacity. The modifications are shown in Appendix B to this Decision.

5. As part of the total package including the TCA modifications, the Settlement Agreement is approved with only minor modifications pertaining to the proposed Energy Insecurity Working Group, some of which were suggested by the City of Boulder (Boulder). As discussed below, the Commission modifies Paragraph 70 of the Settlement Agreement: (1) to require Public Service to include in its reporting on the efforts of the Energy Insecurity Working Group a summary of the options offered for possible paths forward for addressing energy insecurity; and (2) to direct the Energy Insecurity Working Group to develop an outreach program to contact and interview disconnected customers to better understand their circumstances, their

options after disconnection, the barriers and challenges to reconnection, and possible avenues of assistance available as well as efforts to explore new approaches for identifying customers most in need.

B. Procedural Background

6. On November 30, 2022, Public Service filed Advice Letter No. 1906-Electric (Advice Letter No. 1906) with supporting attachments and pre-filed testimony of 20 witnesses to initiate a Phase I rate proceeding, Proceeding No. 22AL-0530E. The proposed effective date of the tariffs filed with Advice Letter No. 1906 was December 31, 2022. However, Public Service stated it anticipated the tariffs would be suspended and set for hearing, in which case, the effective date of the tariffs would be September 7, 2023.

7. With Advice Letter No. 1906, Public Service seeks an overall increase in base rate revenue of about $312.2 million above its current base rate revenue of $2,140.5 million, an increase of about 15 percent. This increase includes transferring into base rates $40.8 million currently recovered through the TCA and $9.0 million currently recovered through the Purchased Capacity Cost Adjustment. The requested rate revenue increase net of these roll-ins is $262 million. Public Service states the increase is necessary because it has made, and will continue to make, extensive capital investments in its system.

8. The bill impact of the requested $262 million rate revenue increase would be an increase of 8.2 percent for average Residential bills and a 7.8 percent increase for Commercial bills.

9. Public Service based its requested increase on a test year ending December 31, 2023, with an overall rate of return of 7.45 percent and a return on equity (ROE) of 10.25 percent.

10. In addition to the change in base rate revenue, including transferring costs from the TCA and Purchased Capacity Cost Adjustment into base rates, Public Service requests approval of an Earnings Sharing Adjustment mechanism, approval of trackers and deferrals and baselines, amortization of deferred costs, and a re-set of the baseline for the Revenue Decoupling Adjustment.

11. On December 9, 2022, UCA filed a protest letter requesting the Commission suspend and set for hearing the tariff sheets filed with Advice Letter No. 1906. UCA challenged whether the overall revenue increase and resulting bill impacts are just, reasonable, and in the public interest, specifically questioning the proposed test year, capital structure, ROE, cost of debt, overall return, and recovery of specific proposed costs.

12. On December 19, 2022, Trial Staff filed a protest letter requesting the Commission suspend and set for hearing the tariff sheets field with Advice Letter No. 1906. Trial Staff raised many of the same concerns as UCA and added, among others, concerns about the treatment of the net gain on sale of the Zuni Tank Farm property, the resetting of trackers and deferrals, the resetting of the baseline of the Revenue Decoupling Adjustment, and the transfer of transmission investment costs from the TCA to base rates.

13. On November 1, 2022, Public Service filed Advice Letter No. 1902-Electric (Advice Letter No. 1902), setting forth the applicable charge for its TCA for effect January 1, 2023 (2023 TCA), in Proceeding No. 22AL-0478E. In Advice Letter No. 1902, Public Service explains the annual 2023 TCA revenue requirement comprises a projected 13-month average net transmission plant not yet included in base rates and year-end 2022 transmission construction work in progress (CWIP). The 2023 TCA will collect approximately $40 million, some $17.8 million more than the TCA in effect for calendar year 2022. The projected bill impact of the increase would be about $0.51 per month for residential customers.

14. On November 29, 2022, Trial Staff filed a protest to Advice Letter No. 1902, requesting the tariff sheets be suspended and set for hearing. Trial Staff contends that Public Service is requesting recovery of costs associated with transmission projects that are not extension or construction of transmission facilities and are therefore ineligible for recovery through the TCA pursuant to § 40-5-101(4), C.R.S.

15. On December 6, 2022, Public Service filed a response to Trial Staff's protest to Advice Letter No. 1902.

16. By Decision No. C22-0833, issued on December 23, 2022, the Commission suspended the effective date of the tariff sheets filed with Advice Letter No. 1906 and Advice Letter No. 1902 to May 1, 2023, pursuant to § 40-6-111(1), C.R.S. Decision No. C22-0833 also consolidated Proceeding Nos. 22AL-0530E and 22AL-0478E.

17. By Decision No. C23-0110-I, issued on February 16, 2023, the Commission granted the requests for intervention filed by the Kroger Co. (Kroger), the City and County of Denver (Denver), Boulder, FEA, CEC, the Coalition for Community Solar Access (CCSA), Walmart, Climax Molybdenum Company (Climax), and Molson Coors. Trial Staff, UCA, and CEO are intervenors by right.

18. By Decision No. C23-0146-I, issued on March 1, 2023, the Commission directed Public Service to file Supplemental Direct Testimony on several topics:

1) 15-year projections of base rate revenue requirements and total retail revenue requirements, as well as the associated projected overall average rates and residential rates;
2) An affordability analysis supported by the appropriate calculation of affordability metrics, with a focus on assessing affordability issues within the Residential rate class;
3) A range of documents associated with the Company's overall financial integrity including, among others, the latest credit ratings from the principal credit rating entities, the Company's understanding of the methodology used by rating agencies for calculating key cash flow metrics, Xcel Energy's recent investor presentations and 2022 Year End Earnings Report, an analysis of credit metrics as used by rating agencies to assess financial integrity

under several scenarios of Commission cost of capital authorization (Scenario Analysis), and a spreadsheet model to evaluate the impact of various financial "Levers" on the Company's credit metrics;

4) Support of the Company's 2023 TCA revenue requirement and response to Trial Staff's allegation that the Company is improperly recovering some transmission investment costs through the TCA;

5) Information regarding the Company's trading operations, the roles of Generation and Proprietary Books in organized wholesale markets, and the incentive structure that are intended to ensure ratepayer benefits from the Company's energy trades in current and emerging wholesale markets;

6) Identification of the percentage of annual revenue recovered through riders for utilities in the proxy group used to establish Public Service's proposed ROE;

7) The proportionality of financial rewards and penalties for performance incentive mechanisms, the totality of the financial awards and penalties available to the Company through current performance incentive mechanisms, and the potential magnitude and impacts of future penalties and incentives relative to the typical components of a typical phase I electric rate proceeding.

19. By Decision No. C23-0158, issued on March 3, 2023, the Commission established a procedural schedule for this Proceeding, including setting June 14, 2023, as the deadline for filing settlements and setting an evidentiary hearing for July 6-7, 10-14, 19-21, 2023. The Commission also suspended the tariff sheets filed with Advice Letter No. 1906 in Proceeding No. 22AL-0530E for an additional 130 days, through September 7, 2023, and the tariff sheets filed with Advice Letter No. 1902 in Proceeding No. 22AL-0478E for an additional 130 days, through September 8, 2023, pursuant to § 40-6-111(1)(b), C.R.S.

20. Public Service filed Supplemental Direct Testimony on March 29, 2023.

21. Answer Testimony was filed on May 3, 2023, by Trial Staff, UCA, FEA, CEC, Boulder, CEO, and Walmart.

22. On May 23, 2023, the Board of Water Works of Pueblo, Colorado (Pueblo Water) filed a Motion for Late-Filed Intervention, stating it had not sought intervention in this Proceeding because it was unaware that Trial Staff would, through its Answer Testimony, suggest that Public

Service re-negotiate its contract with Pueblo Water. As such, Pueblo Water sought to intervene so that its witness could address the water contract concerns through Cross-Answer Testimony.

23. Staff filed a response and objection to Pueblo Water's intervention on May 30, 2023.

24. On May 31, 2023, Public Service filed Rebuttal Testimony and Denver, Boulder, and Pueblo Water filed Cross Answer Testimony.

25. By Decision No. C23-0380-I, issued on June 7, 2023, the Commission granted Pueblo Water's request for late intervention.

26. On June 14, 2023, Public Service filed a Notice of Settlement Progress and Anticipation of Filed Settlement, stating the parties were nearing a settlement of most of the issues in this Proceeding and noting that the parties were working to file a settlement before June 20, 2023.

27. On June 20, 2023, the Settling Parties filed the Settlement Agreement along with a Joint Motion to Approve Settlement Agreement. The Settling Parties state the Settlement includes resolution of: (1) Public Service's revenue requirement and deficiency; (2) the test year and Public Service's rate base methodology and rate base adjustments; (3) Public Service's weighted average cost of capital; (4) Public Service's test year revenue; (5) Public Service's test year operation and maintenance (O&M) expense; (6) rate case expense; (7) treatment of Demand Side Management Cost Adjustment expenses; (8) amortization of other regulatory assets; (9) pre-existing trackers and deferrals and new deferrals requested by Public Service; (10) gain on sale matters; (11) water right and water contract matters; (12) further stakeholder work to address affordability, ongoing system planning, and ratemaking and utility performance incentive matters; and (13) rate implementation and tariff changes.

28. The Settlement Agreement is opposed by Boulder. Denver, Climax, CCSA, Pueblo Water, and Kroger either do not oppose or take no position on the Settlement Agreement.

29. On July 10, 2023, the Commission commenced the evidentiary hearing *en banc*. The evidentiary hearing concluded on July 12, 2023.

30. On May 31, 2023, and July 11, 2023, virtual public comment hearings were held *en banc* via Zoom in order to receive oral comment from the public. The oral comments generally expressed concern that utility bills continue to increase and requested that the Commission decline to grant additional rate increases.

31. On August 4, 2023, Statements of Position (SOPs) were filed by Trial Staff, Boulder, Climax, and CEC; Public Service filed an SOP on the TCA issue. Public Service, UCA, CEC, and CEO filed a Joint SOP on the Coal Plant Deferral; and Public Service, Trial Staff, UCA, CEC, CEO, FEA, Molson Coors, and Walmart filed a Joint SOP on the Settlement Agreement. Denver filed a late-filed SOP on August 8, 2023.

32. In addition to the public comments provided orally at the public comment hearing, the administrative record for this Proceeding includes more than 1,800 written public comments generally opposing any rate increase.

33. The Commission admitted Hearing Exhibit (HE) 1600 and all of the documents listed thereon into evidence, which comprise all the prefiled testimony and attachments in the Proceeding and the Settlement Agreement. In addition, during the course of the hearing, the following hearing exhibits were offered and admitted into the record. Non-confidential exhibits: HE 149 Att. 3 Rev. 1, HE 152, HE 154, HE 155, HE 156, HE 158, HE 160, HE 161, HE 164, HE 165, HE 168, HE 169, HE 170, HE 173, HE 302 Rev. 1, HE 306, HE 307, HE 308, HE 309, HE 310, HE 311, HE 312, HE 313, HE 314, HE 315, HE 316, HE 317, HE 602 Rev. 1, HE 807 Rev.

1, HE 807 Att. 4 Rev. 1, HE 810, HE 811. Confidential and highly confidential exhibits: HE 162C, HE 163C, HE 302C Rev. 1, HE 807HC Att. 4 Rev. 1.

II. LEGAL FOUNDATIONS AND BURDENS OF PROOF

A. Burden of Proof and Burden of Going Forward

34. As the party seeking Commission approval, Public Service bears the burden of proof with respect to the relief sought; and the burden of proof is by a preponderance of the evidence.[1] The evidence must be "substantial evidence," which the Colorado Supreme Court has defined as "such relevant evidence as a reasonable mind might accept as adequate to support a conclusion … it must be enough to justify, if the trial were to a jury, a refusal to direct a verdict when the conclusion sought to be drawn from it is one of fact for the jury."[2] The preponderance standard requires the finder of fact to determine whether the existence of a contested fact is more probable than its non-existence.[3] A party has met this burden of proof when the evidence, on the whole and however slightly, tips in favor of that party.

35. This standard for the burden of proof must be integrated with the understanding that, in the context of a rate case, the Commission acts in its legislative capacity, and the key issues require policy-based decisions in order to adopt a particular regulatory principle or to change an existing regulatory principle. As such, the Commission "may set rates based on the evidence as a whole" and "need not base its decision on specific empirical support in the form of a study or data."[4]

[1] § 24-4-105(7), C.R.S.; § 13-25-127(1), C.R.S.; Rule 1500 of the Commission's Rules of Practice and Procedure, 4 *Code of Colorado Regulations* (CCR) 723-1.

[2] *City of Boulder v. Pub. Utils. Comm'n*, 996 P.2d 1270, 1278 (Colo. 2000) (*quoting CF&I Steel, L.P. v. Pub. Utils. Comm'n*, 949 P.2d 577, 585 (Colo. 1997)).

[3] *Swain v. Colo. Dep't of Revenue*, 717 P.2d 507, 508 (Colo. App. 1985).

[4] *Colo. Off. of Consumer Couns. v. Pub. Utils. Comm'n*, 275 P.3d 656, 660 (Colo. 2012).

36. Because the Commission has an independent duty to determine matters that are within the public interest,[5] the Commission is not bound by the proposals of the parties. The Commission may do what it deems necessary to assure that the final result is just, reasonable, and in the public interest, provided the record supports the result, and provided the reasons for the policy choices made are stated.[6]

37. The Commission's Rule 1408(b), 4 CCR 723-1, allows the Commission to approve, deny, or require modification to any settlement as the public interest requires. The Commission considers whether the settled terms adequately address the issues raised in the proceeding and reach a result that is just and reasonable and in the public interest. As the proponents of an order, the settling parties bear the burden of proof to establish by a preponderance of the evidence that the settlement is just and reasonable and in the public interest.[7] In determining whether to approve a settlement, the Commission balances the longstanding policy of encouraging settlements in contested cases[8] and the Commission's independent duty to determine whether matters are in the public interest.[9] The Commission does not necessarily need to find the settled terms are the same as the Commission would have reached; rather, the Commission considers whether the settled terms adequately address the issues raised in the proceeding and reach a result that is just and

[5] *Caldwell v. Pub. Utils. Comm'n*, 692 P.2d 1085, 1089 (Colo. 1984).

[6] *See, Colo. Off. of Consumer Couns.*, 275 P.3d at 660-61; *Pub. Serv. Co. v. Pub. Utils. Comm'n*., 26 P.3d 1198, 1207-08 (Colo. 2001) (holding the Commission acted reasonably in its legislative capacity to accomplish its ratemaking function when it required utility to include a merger savings adjustment to benefit ratepayers because there was sufficient support in the record); *CF&I Steel*, 949 P.2d at 586-87; *Colo. Off. of Consumer Couns. v. Pub. Utils. Comm'n,* 786 P.2d 1086, 1095-97 (Colo. 1990) (holding the Commission did not act arbitrary or capriciously in setting rates, even though it did not accept any of the experts' opinions in full); *Pub. Serv. Co. v. Pub. Utils. Comm'n,* 653 P.2d 1117, 1120 (Colo. 1982) (holding the Commission did not abuse its discretion when it chose not to include out-of-test year debt cost because the decision was reasonable and based on the record).

[7] § 24-4-105(7), C.R.S.; § 13-25-127(1), C.R.S.; Rule 1500, 4 CCR 723-1.

[8] *See*, *e.g.*, Rule 1408 of the Commission's Rules of Practice and Procedure, Rule 4 CCR 723-1.

[9] *See, e.g.,* Proceeding No. 11A-833E, Decision No. C12-1107 at ¶ 31 (issued Sept. 24, 2012) (citing *Caldwell*, 692 P.2d at 1089).

reasonable and in the public interest. The Commission applies these principles and legal standards here to assess the Settlement Agreement as a resolution of the settled issues in this Proceeding.

B. Commission Jurisdiction

38. Rates and charges for public utility service are to be just and reasonable pursuant to § 40-3-101(1), C.R.S. The Colorado Supreme Court has held it is the primary purpose of utility regulation to ensure the rates charged are not excessive or unjustly discriminatory.[10] Further, § 40-3-101(2), C.R.S., requires a utility to provide such service and facilities as shall promote the safety, health, comfort, and convenience of its patrons, employees, and the public, and as shall in all respects be adequate, efficient, just, and reasonable.

39. The setting of just and reasonable rates, both as to level and design, goes to the very essence of the Commission's powers and duties.[11] The Commission is an administrative agency of the legislature,[12] charged with the authority, and duty, to regulate the rates of public utilities operating within Colorado. *See* § 40-3-102, C.R.S. (vesting in the Commission the power to regulate all rates, charges, and tariffs of every public utility in this state and to do all things necessary or convenient in the exercise of such power); Colo. Const. Art. XXV (affirming General Assembly's power to regulate public utility facilities, service, and rates and charges, and delegating that power in all respects to the Commission); *Miller Brothers v. Pub. Utils. Comm'n.*, 185 Colo. 414, 525 P.2d 443, 451 (1974) (holding Commission has as much authority as General Assembly possessed prior to the adoption of Art. XXV in 1954, unless and until the General Assembly enacts a specific statutory restriction on the Commission's authority, which then

[10] *Cottrell v. City & County of Denver*, 636 P.2d 703, 711 (Colo. 1981).

[11] *Colorado-Ute Elec. Ass'n, Inc. v. Pub. Utils. Comm'n*, 760 P.2d 627, 638 (Colo. 1988).

[12] By the Public Utilities Act of 1913, codified at § 40-3-102, C.R.S., the legislature created the Commission and vested it with jurisdiction over the regulation and control of public utilities. *See People v. Colorado Title & Tr. Co.*, 65 Colo. 472, 480, 178 P. 6, 10 (1918).

controls; these principles of Colorado constitutional law are known as the "*Miller Brothers* Doctrine").

40. Pursuant to these statutory and constitutional authorities, the Commission has a general responsibility to protect the public interest regarding utility rates and practices and has broadly based power to do whatever it deems necessary or convenient to accomplish this function.[13] In fulfilling this duty, the Commission conducts hearings to investigate the propriety of a public utility's proposed rate changes and to determine the just and reasonable rates to be charged.[14] Indeed, § 40-3-111, C.R.S., expressly authorizes the Commission to determine the just and reasonable rates to be charged to customers by public utilities.

41. Under the just and reasonable standard, the Commission considers both consumers' interest in preventing exorbitant rates and the utility investors' interest in avoiding confiscation.[15] This requires the Commission to protect the public interest by ensuring that rates are not excessive, burdensome, or unjustly discriminatory, while protecting the right of the utility and its investors to earn a return reasonably sufficient to maintain the utility's financial integrity. So far as the utility is concerned, it must have adequate revenues for operating expenses and to cover the capital costs of doing business and its revenues must be sufficient to assure confidence in its financial integrity so as to maintain credit and to attract capital. Consequently, "just and reasonable" rates set by the Commission protect both: (1) the right of consumers to pay a rate which accurately reflects

[13] *City of Montrose v. Pub. Utils. Comm'n*, 629 P.2d 619, 623 (Colo. 1981).

[14] *See* § 40–3–111, C.R.S.; *CF&I Steel*, 949 P.2d at 584 (finding the Commission has the duty to examine proposed rates and to determine whether they are unjust, unreasonable, discriminatory, or preferential, or in any way violate any provision of law, and if so, to set just and reasonable rates).

[15] *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 64 S.Ct. 281, 88 L.Ed. 333 (1944); *Colo. Mun. League v. Pub. Utils. Comm'n*, 687 P.2d 416, 418 (Colo. 1984).

the cost of service rendered; and (2) the right of the utility and its investors to earn a return reasonably sufficient to maintain its financial integrity.[16]

42. However, pursuant to well established principles of regulatory law and public policy, the Commission does not guarantee rates of return. The Commission's responsibility is to set a rate of return which the utility then has the opportunity to earn, through efficient operations. Unless a utility bears some risk, it lacks the proper incentive. Thus, the "just and reasonable" rates authorized for the utility incorporate the principle that the Commission-authorized rate-of-return provides an opportunity, not a guarantee, to earn its authorized amount.

43. In the ratemaking process, the Commission necessarily exercises much judgment and discretion.[17] As the Colorado Supreme Court has long recognized:

> [R]ate making is not an exact science. Those charged with the responsibility of prescribing rates have to consider the interests of both the investors and the consumers. Sound judgment in the balancing of their respective interests is the means by which a decision is reached rather than by the use of a mathematical or legal formula. After all, the final test is whether the rate is 'just and reasonable.' And, of course, this test includes the constitutional question of whether the rate order 'has passed beyond the lowest limit of the permitted zone of reasonableness into the forbidden reaches of confiscation.'[18]

Because of the level of judgment required, the Commission "may set rates based on the evidence as a whole" and "need not base its decision on specific empirical support in the form of a study or data."[19] The Colorado Supreme Court has described the Commission's evaluation as "a stream bounded on each side by the limits of discretion" and instructed reviewing courts to determine whether the Commission's end result stayed within its discretionary channels.[20]

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[16] *Pub. Serv. Co. of Colo. v. Pub. Utils. Comm'n*, 644 P.2d 933, 939 (Colo. 1982).

[17] *See Mountain States Tel. & Tel. Co. v. Pub. Utils. Comm'n*, 182 Colo. 269, 279–80, 513 P.2d 721, 726 (1973) (explaining the Commission must have before it evidence on the subject matter, but the determination as to what is a fair, just and reasonable rate is a matter of judgment or discretion).

[18] *Pub. Utils. Comm'n v. Northwest Water Corp.*, 168 Colo. 154, 173, 451 P.2d 266, 276 (1963) (internal citations omitted).

[19] *Colo. Off. of Consumer Couns.*, 275 P.3d at 660.

[20] *Colo. Mun. League v. Pub. Utils. Comm'n*, 172 Colo. 188, 210-11, 473 P.2d 960, 971 (1970).

44. When the Commission establishes rates, it is the result reached, not the method employed, that determines whether a rate is just and reasonable.[21] When ratemaking, the Commission applies regulatory principles and methods to determine a utility's revenue requirement. The Colorado Supreme Court has noted that "[s]ince rate setting is a legislative function which involves many questions of judgment and discretion, courts will not set aside the rate methodologies chosen by the [Commission] unless they are inherently unsound."[22] Further, "the [Commission] is not bound by a previously utilized methodology when it has a reasonable basis, in the exercise of its legislative function, to adopt a different one."[23] In ratemaking as well as other matters, the Commission is not bound by its prior decisions or by any doctrine similar to *stare decisis.*[24] The appearance of arbitrariness is dispelled when new findings are made on the basis of new evidence and a new record.[25]

45. Finally, as explained in greater detail below, the Commission establishes rates in consideration of the utility's annual revenue requirements as calculated by over a Commission-selected test year. The revenue requirement is the total revenues sought by the utility to cover both its expenses and to have a fair or reasonable opportunity to earn a fair rate-of-return, and in return, to provide safe, reliable service to its customers.[26]

[21] *Glustrom v. Pub. Utils. Comm'n*, 280 P.3d 662, 669 (Colo. 2012); *Colorado-Ute Elec. Ass'n, Inc. v. Pub. Utils. Comm'n,* 198 Colo. 534, 538, 602 P.2d 861, 864 (1979) (citing *Hope*).

[22] *CF&I Steel*, 949 P.2d at 584.

[23] *Id*.; *see also Glustrom*, 280 P.3d at 669 (noting a court on judicial review would overstep its role and demean the Commission's authority in the legislative field of ratemaking were it to insist the Commission revise its method in the absence of persuasive evidence that the challenged method is inherently unsound).

[24] *Colorado-Ute,* 198 Colo. at 540–41, 602 P.2d at 865.

[25] *Id*.

[26] *See, e.g.*, *Pub. Serv. Co.*, 644 P.2d at 939.

III. SETTLEMENT AGREEMENT

A. Test Year, Revenue Requirement, and Rate Base

46. The Settlement Agreement results in a base rate revenue requirement of $2.176 billion, using a test year of the 12 months ending December 31, 2022 (Settlement Test Year). The December 31, 2022, informational test year revenue requirement provided in the Company's Supplemental Direct Testimony,[27] with some modifications, serves as the basis for the Settlement Test Year. The $2.176 billion base rate revenue requirement is an increase of $45 million above the current revenue of $2.131 billion.

47. The Settlement Agreement also allows for the transfer of some $89.5 million for demand side management programs currently collected through base rates to Public Service's Demand Side Management Cost Adjustment. Additionally, recovery of $30.7 million in transmission investment costs from the TCA and $8.9 million from the Purchased Capacity Cost Adjustment for the Manchief Generating Station are transferred into base rates.

48. The Settlement Agreement explains the intervening parties made various proposals that would reduce the revenue requirement and, in consideration of those, Public Service agrees to a $5.0 million revenue requirement reduction.

49. The resulting total retail revenue increase is $96.8 million. The Coal Plant Deferral, if approved, would result in a total retail revenue increase of $47.9 million. Recovery of the base rate revenue deficiency will be accomplished through a GRSA and GRSA-E, effective September 1, 2023. Without the Coal Plant Deferral, the GRSA would be 2.74 percent and the GRSA-E would be $0.00214/kWh for Residential class customers and $0.00192/kWh for Commercial class customers. With the Coal Plant Deferral, the GRSA would be 0.15 percent and the GRSA-E would

[27] Hrg. Exh. 129, Freitas Supplemental Direct, Attachment APF-23.

be -($0.00008)/kWh for Residential class customers and -($0.00009)/kWh for Commercial class customers.

B. Capital Structure and Weighted Average Cost of Capital

50. The Settlement Agreement includes an authorized ROE of 9.30 percent and a weighted average cost of capital (WACC) of 6.95 percent. This WACC is based on the Company's actual capital structure as of December 31, 2022, of 55.69 percent equity, 43.30 percent long-term debt, and 0.91 percent short-term debt. The cost of long-term debt is 4.01 percent, and the cost of short-term debt is 3.81 percent.

C. Bill Impact

51. Schedule R (Residential) and Schedule C (Commercial) average monthly bill impacts resulting from the Settlement Agreement's revenue requirement and dependent on the Commission's decisions regarding the Coal Plant Deferral and TCA recovery are shown in the table below:

	With Coal Deferral and Full Year TCA	With Coal Deferral and 4-Month TCA	Without Coal Deferral and Full-Year TCA	Without Coal Deferral and 4-Month TCA
Schedule R	1.72%	2.93%	3.22%	4.43%
Schedule C	1.80%	2.82%	3.21%	4.23%

D. Plant and Plant-Related Balances

52. Plant and plant-related balances included in rate base for the Settlement Test Year are based on the Company's data provided in its Supplemental Direct Testimony.[28] Although the Company had proposed an alternative method for calculating cash working capital, the Settling

[28] Hrg. Exh. 126, Moeller Supplemental Direct, Attachment MPM-7.

Parties agreed to the methodology previously used in the Company's 2021 phase I electric rate proceeding, Proceeding No. 21AL-0317E.

E. O&M Expenses

53. The Settlement Test Year Operations and Maintenance (O&M) expenses are based on 2022 historical O&M, including known and measurable adjustments as included in the Company's Informational Historical Test Year.[29] However, the Company's Annual Incentive Plan (AIP) expense is capped at 15 percent of base salary, calculated on an employee-by-employee basis and the Settlement Test Year revenue requirement includes the time-based portion of the Company's Long-Term Incentive (LTI) but excludes the environmental portion of the LTI.

54. The prepaid pension asset and prepaid retiree medical asset are included in rate base on a 13-month average basis as of December 31, 2022, and will earn a return equal to the Company's WACC. Additionally, the prepaid retiree medical asset will not be amortized, and the prepaid pension asset will continue to be amortized annually at $3,125,458 as stipulated in prior Proceeding No. 21AL-0317E.

F. Cabin Creek

55. The Settlement Agreement allows the costs for the Cabin Creek Hydroelectric Station (Cabin Creek), including the Cabin Creek Facility Project costs in-service as of December 31, 2022, will be included at the levels included in the 2022 Settlement Test Year, without adjustment. A holistic prudence review of the Cabin Creek Facility Project will proceed as provided for in the settlement agreement in Proceeding No. 22A-0345E and may include the capital expenditures and operating and maintenance costs, as well as issues of prudence and

[29] Hrg. Exh. 129, Freitas Supplemental Direct, Attachment APF-23.

usefulness as it relates to the asset's inclusion in rate case, associated with the Cabin Creek Facility Project.[30]

G. Rate Case Expenses

56. The Settlement Agreement allows recovery of actual rate case expenses incurred by the Company for this Phase I rate proceeding and the pending Phase II rate proceeding (Proceeding No. 23AL-0234E), capped at $2 million and amortized over 36 months from the rate effective date in this Proceeding.

H. Wildfire Management Program

57. The Settlement Test Year revenue requirement includes the transfer of Wildfire Mitigation Program (WMP) capital into base rates at the December 31, 2022 year-end value and the transfer of WMP O&M into base rates. The deferral of WMP expenses will continue through December 31, 2023, at a return equal to the long-term cost of debt. While the WMP deferral will not extend past December 31, 2023, the Company may file a request to extend the deferral in another proceeding.

I. Advanced Grid Intelligence and Security CPCN Deferral

58. The Settlement Agreement allows for the continuation of the Advanced Grid Intelligence and Security Certificate of Public Convenience and Necessity (AGIS CPCN) deferral, with a return equal to the Company's WACC, as authorized in Proceeding Nos. 21AL-0317E and 19AL-0268E.

[30] *See* Hrg. Trans. July 12, 2023 (Pereira) at p. 42:20–25; July 11, 2023 (O'Neill) at p. 39–40; July 10, 2023 (Berman) at p. 109–112.

J. Pension Expense Tracker, Property Tax Tracker, ICT Projects

59. The Settlement Agreement also allows the continuation of the Pension Expense Tracker, Property Tax Tracker, and deferral of capital costs and O&M expenses for Innovative Clean Technology (ICT) projects, consistent with previous Commission decisions.

K. Revenue Decoupling Adjustment Pilot

60. The Settling Parties agree that the Revenue Decoupling Adjustment (RDA) Pilot will end on the first of the month in which rates become effective and Public Service will no longer measure Lost Fixed Cost Recovery after that date. RDA deferrals remaining after the two-year deferral period allowed under the RDA Pilot Tariff will offset other deferred balances and the value of those deferrals will be credited to the Residential and Small Commercial customer classes.

L. Zuni Tank Farm

61. The Settling Parties do not agree conceptually how the sharing of the Zuni Tank Farm property gain on sale should be structured between ratepayers and the Company or on any broad rules or principles for the handling of gains from the sale of non-depreciable assets. However, the Settling Parties agree that the $5 million allowance resolves this issue solely for the purposes of this Proceeding. Additionally, the Company agrees to work with Trial Staff and UCA, beginning no later than December 31, 2023, on appropriate tracking of expenses that relate to the increase or decrease in value of non-depreciable assets.

M. 2023 TCA

62. The Settling Parties agree that no changes will be made to the TCA structure, scope, and calculation methodology for the 2023 TCA and agree that the incremental 2023 TCA forecast, as filed on November 1, 2022, that is not currently being recovered pending resolution of this

combined rate case and TCA proceeding, will be recovered through the TCA over the period from the implementation of final rates in this Proceeding to December 31, 2023.

N. Water Rights

63. With regard to water rights, the Public Service agrees to remove from the Settlement Test Year revenue requirement the Southeast Water Rights debt return, and the lease revenues associated with the Southeast Water Rights, as well as certain other water rights amounts associated with McDonald Ditch (Alamosa), Lacombe Power Plant Right (Zuni), and Sethman Pipeline No. 1 and 2 (Salida Hydro Unit 1). Additionally, Public Service agrees to include water rights that are not currently used for electricity generation in its next Electric Resource Plan filing, or in another filing prior to December 31, 2025. Public Service also agrees to explore options to mitigate the rate impact of the Pueblo Water contract and will report annually on or about October 1 in this Proceeding (beginning October 1, 2024), as well as in the Company's next Phase I electric rate proceeding.

O. Distribution System Barriers to Electrification Projects

64. In order to address issues raised by Denver in this Proceeding regarding distribution system barriers in building electrification projects, within 90 days of a Commission decision in this Proceeding, the Company will work with the parties to the settlement approved in Proceeding No. 22A-0189E, Public Service's Distribution System Planning proceeding, to request the opening of a miscellaneous proceeding as contemplated in that settlement.

P. Non-Litigated Proceeding on Goals of Electric Utility Service

65. The Company and other interested Settling Parties will file a request for the Commission to open a non-litigated proceeding to evaluate the goals of electric utility service, to consider the role and potential structure of performance metrics to achieve the desired outcomes

of utility service, and to consider a performance-based regulatory framework to achieve those goals.

Q. Energy Insecurity

66. To address the issues of energy insecurity raised by CEO in this Proceeding, Public Service will work with stakeholders in Proceeding No. 23M-0013EG to develop a consensus estimate of the number of energy insecure customers, and to discuss potential actions to reduce energy insecurity, including for customers near the household income thresholds for energy assistance programs and how to account for building, heating, and/or transportation electrification in the definition of energy insecurity. Within six months of a final Commission decision in this Proceeding, Public Service will file a narrative description summarizing the data, discussion, proposed solutions, areas to further explore, and areas of disagreement among stakeholders.

R. Boulder's Opposition to the Settlement Agreement

67. Boulder contends the Commission should reject the Settlement Agreement because the ROE of 9.3 percent and WACC of 6.9 percent are unnecessarily high relative to the Company's peers and given the risk incurred by the Company. Boulder also requests changes to the directives and leadership of the Energy Insecurity Working Group and recommends the Commission consider the Company's willingness to settle the rate case when awarding rate case expenses.

1. ROE and WACC

68. Boulder suggests adopting a ROE of 8.51 percent, consistent with the Company's actual earned return in the five-year period of 2017-2022. Boulder contends the national trend is for a stable or declining ROE. Boulder argues, while customers are struggling with rising costs,

the Company is more profitable than all but one of its proxy group companies. Boulder adds that the requested ROE does not match Public Service's risk profile.[31]

69. Boulder agrees with Trial Staff's suggestion that setting a lower ROE is one tool the Commission has to address customer complaints,[32] and that the Commission should tie its authorized ROE to the Company's performance on affordability, customer service, and project management.[33] Boulder refers to the Company's Scenario Analysis, which forecasts Public Service's financial integrity and suggests, even without a rate increase, the Company's credit metrics maintain a healthy margin above the threshold between its current and lower bond ratings.

70. Boulder also notes the proposed WACC of 6.95 percent represents an increase relative to the WACC approved in the Company's prior rate case decision due to the increased cost of debt.[34] Boulder contends a higher WACC typically indicates increased risk, and that, as the parent of regulated utilities and with increasing dividends, Xcel Energy is not truly subject to more risk.

71. Boulder contends the Settlement Agreement's WACC of 6.95 percent is higher than the WACC set in two other recent cases for Xcel Energy operating companies in Minnesota and South Dakota.[35] Specifically, Boulder notes that on June 1, 2023, the Minnesota commission set the WACC for Xcel Energy's electricity business at roughly 6.84 percent (including an authorized ROE of 9.25 percent), and on June 6, 2023, the South Dakota commission set the WACC for Xcel's electricity business at 6.82 percent.

[31] Hrg. Exh. 600C, Lehrman Answer Rev. 1, p. 10:10–11:4.
[32] Hrg. Exh. 601, Lehrman Cross-Answer, p. 7:4–6 (citing Hrg. Exh. 802, Fuller Answer, p. 66:7–67:18).
[33] *Id*., p. 9:4–7.
[34] Hrg. Exh. 602, Lehrman Settlement, p. 4:1–9.
[35] *Id*., p. 4:10–16, citing: *PUC Staff Memorandum Supporting Settlement Stipulation, Exhibit BLC-1,* South Dakota Public Service.

72. Boulder also remarks that 2022 "was a year of record Xcel Energy profits, record customer requests for bill pay assistance, a record amount of customer bills in arrears and an unprecedented number of ratepayer comments and complaints regarding high bills…"[36]

73. In its SOP, Boulder contends, if the Commission rejects its proposal to limit the ROE to 8.51 percent and the WACC to 6.51 percent, the authorized WACC should not exceed 6.82 percent and the ROE must not exceed 9.3 percent, as approved in Proceeding No. 21AL-0317E, which was Public Service's last electric rate case. Boulder states this can be achieved by either lowering the equity ratio 53.2 percent or by reducing the ROE to 9.06 percent and maintaining the 55.69 percent equity ratio.

74. Boulder claims Public Service's witness Paul Johnson agreed at hearing that the rate case was not needed to maintain the Company's financial integrity and that Trial Staff made statements indicating Public Service is financially healthy. Boulder argues that comparisons between the Xcel stock price and the S&P 500 are inappropriate and inconsistent with the comparable risk standard developed in the federal case law *Hope* and *Bluefield*.[37] Boulder rejects the Company's concerns of a "less supportive regulatory environment" as baseless, citing the Company's multiple, overlapping proceedings initiated by the Company itself, the significant capital investment that has taken place, and the number of riders for cost recovery of specific projects and products.[38]

[36] Hrg. Exh. 602, Lehrman Settlement, p. 5:1–4.

[37] Boulder SOP, p. 6 (citing *Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of West Virginia*, 262 U.S. 679, 692–93 (1923); *Hope*, 320 U.S. 591.

[38] *Id*., p. 7. Boulder lists the following riders utilized by Public Service: Demand-Side Management Cost Adjustment, Renewable Energy Standard Adjustment, Transportation Electrification Program Adjustment, Colorado Energy Plan Adjustment, Extraordinary Gas Cost Recovery Rider, Transmission Cost Adjustment, Purchase Capacity Cost Adjustment, and Electric Commodity Adjustment.

75. In Public Service's Rebuttal Testimony and in the Settling Parties' Joint SOP, the parties reject Boulder's arguments, responding that Boulder witness Lehrman did not perform any quantitative analysis regarding his ROE suggestion.[39] Public Service further argues that Boulder's proposal is inconsistent with the significant changes in market conditions, specifically that 30-year Treasury bond yields have increased by 160 basis points since its last rate proceeding.

76. Public Service's ROE witness, Ann Bulkley, also contends she is not aware of any state or Federal regulatory commission in the U.S. that sets utility authorized returns on historical earned returns, and that Mr. Lehrman's suggestion is inconsistent with the seminal *Hope* and *Bluefield* decisions, which require a utility be given the opportunity to earn a return that is commensurate with investments of similar risk, referred to as the comparable return standard. Public Service further argues that Mr. Lehrman is not recommending eliminating regulatory lag, the primary cause of underearning, and that the effect of setting an 8.5 percent authorized would, if a historic test year is imposed, in actuality cause an earned return of more like 7.5 percent.[40]

77. Public Service also argues that recent ROEs awarded to electric utilities in 2023 have averaged 9.76 percent and have generally risen due to recent increases in Treasury bond rates. Public Service presented analysis after the hearing that the Commission's approval of the Settlement Agreement will cause the Company's key credit metrics to remain in a stable range necessary to support the Company's current bond rating, as calculated by Moody's and S&P credit rating agencies.

78. Addressing Boulder's critique that the appropriate proxy group for the ROE analysis would be drawn from the Mountain West, the Company and other Settling Parties point

[39] Hrg. Exh. 134, Bulkley Rebuttal Rev. 1, p. 11:10–11; Joint Settlement SOP, p. 22.
[40] Hrg. Exh. 134, Bulkley Rebuttal Rev. 1, p. 12:29–31.

out that Boulder's "Mountain West Proxy Group" has an average ROE of 9.48 percent – which is materially higher than the Settlement Agreement's ROE and nearly a full percentage point higher than the ROE that Boulder recommended in its testimony opposing the Settlement Agreement.[41]

79. The Settling Parties contend that Boulder's concerns that the higher overall WACC does not represent actual risk are misplaced because, as Boulder acknowledges, the cost of debt is a real cost to the Company, in the form of interest on debt it must pay to lenders. They maintain, the higher cost of debt, and thus the WACC as well, is a direct result of rising interest rates and market conditions and Public Service will not earn a higher rate of equity return as a result of the Settlement Agreement.[42]

80. Public Service contends the Commission should reject Boulder's recommendations for a lower ROE and WACC because Boulder failed to provide an analysis of the effect Boulder's recommendations would have on the Company's credit metrics or financial integrity.[43]

81. Staff separately supported the Settlement Agreement, contending it is "reasonable to increase the Company's WACC to 6.95 percent to accommodate the increased cost of debt [and] the Company's current ROE of 9.30 percent remains reasonable and appropriate for the current conditions."[44]

82. The Settling Parties contend the settled WACC reflects the capital structure initially recommended by Trial Staff and the Company, the ROE recommended by UCA (and between the recommendations of several parties), and the Company's anticipated actual cost of debt.[45]

[41] Joint Settlement SOP, p. 22.
[42] *Id*., p. 20–21.
[43] Public Service SOP, p. 22, citing Tr. Vol. II p. 222:18–224:5.
[44] Trial Staff SOP, p. 2.
[45] Joint Settlement SOP, p. 26.

83. In response to Commission questions and statements at hearing and in prior cases, the Settling Parties argued that the Settlement Agreement purposely defines *specific* ROE and WACC values, rather than ranges, for a variety of reasons including the calculation of Allowance for Funds Used During Construction and to determine taxes payable and overall revenue requirement. The Settling Parties argue that "replacing these negotiated and agreed-upon components with a WACC that could be composed of a range of varying elements may introduce uncertainty into what parties are agreeing to, thereby actively discouraging future settlement resolutions."[46]

2. Energy Insecurity Working Group

84. The Settlement Agreement establishes an Energy Insecurity Working Group in which Public Service agrees to work with stakeholders in Proceeding No. 23M-0013EG to develop an estimate of the number of energy insecure customers, consistent with the definitions in Commission rules and Pathways to Energy Affordability in Colorado study, to discuss potential actions to reduce energy insecurity for customers, including those near energy assistance program thresholds and how to include electrification in energy insecurity definitions. The Company agrees to file a narrative summarizing these discussions within six months of a final decision in this Proceeding.[47]

85. In its testimony opposing the Settlement Agreement, Boulder raises four specific objections to this settled term:

1) The lack of a requirement to quantify the annual cost of energy insecurity, defined by Boulder as the amount bills must be reduced so that no customer pays more than four percent of annual income on energy bills. Having this information would allow the development of tools to eliminate energy insecurity.

[46] Joint Settlement SOP, p. 25.

[47] Settlement Agreement, ¶ 70.

2) The lack of a requirement that Public Service reduce insecurity for any customer paying more than four percent of total household income for energy.

3) The implication that energy assistance programs are the answer to addressing energy insecurity, and the lack of a definition of customers who are "near" energy assistance program thresholds.

4) Public Service's methodology of estimating energy insecure customers by dividing bills by median income at the census block level, which Boulder contends masks key data and does not consider the possibility that most residents in a census tract could earn less than the median income for that census tract.[48]

86. Boulder recommends using a third-party facilitator to run the stakeholder workshop, noting it has doubts as to both Public Service's commitment to reducing energy insecurity and its ability to design and implement a stakeholder process. Boulder questions Proceeding No. 23M-0013EG as the venue for the stakeholder process, recommending instead the process be part of a rate case because these proceedings address investments and operations. Boulder also argues that the Commission's Affordability Initiative work plan, Proceeding No. 22M-0171ALL, and the affordability programs in Proceeding Nos. 23AL-0176E and 0177G, would be appropriate venues for this work.

3. Recovery of Legal Costs

87. Boulder notes that Public Service was willing to settle for 80 percent less than its initial case and questions the $2 million allowed for rate case costs. Boulder suggests the Commission evaluate opportunities to mitigate inappropriate and unnecessary litigation in the future.

S. Commission Findings and Conclusions

88. Based upon substantial evidence in the record, the Commission finds approval of the Settlement Agreement is in the public interest as part of a broader and balanced package that

[48] Hrg. Exh. 602, Lehrman Settlement, p. 8:1–11:6.

includes modifications to the TCA as described below. The Commission finds the Settling Parties have established by a preponderance of the evidence that the Settlement Agreement, when coupled with the TCA modifications contained in this order, is just, is reasonable, and should be accepted by the Commission. We therefore simultaneously approve the Settlement Agreement along with the TCA reforms as a comprehensive package, with only the relatively minor other additions as set forth below.

89. Based on our review of the evidence in the record overall and our consideration of the provisions of the Settlement Agreement, we approve the revenue requirement resulting from the Settlement Agreement and, with the modifications discussed below, we approve the Settlement Agreement, including a historic test year representing the 13 months that end December 31, 2022; an end-of-year convention to calculate a rate base of approximately $10.56 billion; and an authorized ROE at 9.3 percent, the equity ratio at 55.69 percent, and the WACC at 6.95 percent.

90. With respect to equity ratio, we note the record demonstrates the settled value of 55.69 percent is above the median and average equity ratios of the proxy group, calculated as 52.78 percent and 53.19 percent, respectively. We also note the parties here proposed equity ratios ranging from a low of 46 percent up to a high of just under 56 percent, representing a range of nearly 10 percent. Given the broad range presented, we have significant concerns as to how the outcome landed at the top of the range, and why the settled value is specific to the hundredth of a percentage point despite prior Commission decisions finding such an approach to be overly precise.[49]

[49] *See, e.g.*, Proceeding No. 22AL-0046G, Decision No. C22-0642 at ¶¶ 145–146 (issued October 25, 2022).

91. At the same time, we recognize that the Settlement Agreement was supported by a wide range of entities representing diverse interests including Trial Staff, UCA, business groups, and large commercial customers of Public Service. We also note the Settling Parties "are asking the Commission to determine that the Settlement Agreement as a whole, including the agreed-upon components of the WACC, fall within a range of reasonableness and result in just and reasonable rates."[50]

92. As a result, while we may not completely agree with the specific component settings and might have arrived at a different result if the proceeding were fully litigated, we find the resulting rates represent a just and reasonable balance, when considered along with the modifications to the TCA outlined later in this Decision. When considered as a comprehensive package, including the modifications to the TCA, we find the Settlement Agreement's proposed WACC of 6.95 percent generally balances a relatively high equity ratio with a relatively modest return on equity to provide a reasonable overall return on invested capital. We thus conclude the Settlement Agreement's proposed WACC, including the balance created by the modification to the TCA, can facilitate the Company's ability to attract future capital investments for the benefit of its ratepayers at a realistic cost. We also note the Company's financial integrity, as measured by its assessment of credit metrics, is projected to remain in stable territory under the terms of the Settlement Agreement; we find this generally benefits customers as it indicates the Company will be able to raise debt at relatively low rates and have the financial strength to meet challenging circumstances such as those brought on by Winter Storm Uri 2021 and other recent events.

93. With regard to the Energy Insecurity Working Group, we acknowledge Boulder's concern that this Working Group produce actionable data but are mindful that the goal of the

[50] Joint Settlement SOP, p. 25.

Working Group is not to eradicate energy insecurity but to begin to understand the problem itself, before exploring paths to reducing energy insecurity. The Settlement Agreement allows only six months for the Company to convene the Working Group and then present its report. Thus, the Working Group must be focused on the issues identified in the Settlement Agreement. Given the relatively limited six-month timeline, we find it is appropriate for Public Service to lead the Working Group, with the participants determining, as part of their discussions, whether another entity is available to lead future work. Additionally, we find it is appropriate to require that Public Service include in its report a summary of options the Working Group offers for possible paths forward for addressing energy insecurity. We modify Paragraph 70 of the Settlement Agreement accordingly.

94. Also, considering the testimony provided in this Proceeding regarding energy insecurity, we find there are many more customers requiring assistance with their energy bills than we have resources available. We therefore direct the Energy Insecurity Working Group to develop an outreach program to contact and interview disconnected customers to better understand their circumstances, their options after disconnection, the barriers and challenges to reconnection, and possible avenues of available assistance. We note there are likely two types of disconnected customers: those who have their service re-connected fairly quickly and those who remain disconnected. We therefore direct the Working Group to consider both types of customers in their outreach. Additionally, we request that the Company assist with this outreach, and broader efforts to provide customer support to those most in need, by making available customer data (consistent with the Commission's Rules 3027–3033, 4 CCR 723-3) regarding arrearage, assistance requests, payment, and disconnect history in order to help better target those customers. We leave to the Working Group the determination as to what information is the most beneficial to its work to

establish a path forward in addressing energy insecurity and request the Working Group identify the types of data and the timeline necessary to receive this data and that Public Service include these determinations in its report filed with the Commission. The details of the outreach program shall be included in the report on the Working Group filed by Public Service within six months of the issuance of this Decision. We modify Paragraph 70 of the Settlement Agreement to reflect these changes.

IV. LITIGATED ISSUES

95. The Settling Parties reserved for litigation and Commission determination: (1) whether to accept or reject the Coal Plant Deferral; and (2) whether to modify the Company's TCA prospectively, for implementation beginning January 1, 2024.

A. Coal Plant Deferral

96. Public Service plans to retire coal-fired generation facilities at its Comanche, Craig, and Hayden stations and to convert the coal-fired generation facilities at its Pawnee station to natural gas-fired facilities.[51]

1. Party Positions

97. In Answer Testimony,[52] UCA proposed mitigating the rate increase resulting from this Proceeding by deferring the recovery of certain costs associated with the coal-fired power plants whose net plant costs were recently addressed in Proceeding No. 22A-0515E: Comanche 3, Craig 2, Hayden 1, Hayden 2, and Pawnee. These additional costs, included in the revenue requirement for setting base rates in this Phase I rate proceeding, would be deferred and then added

[51] The retirement or conversion of the coal-fired generation facilities are addressed in Public Service's ongoing Electric Resource Plan and Clean Energy Plan in Proceeding No. 21A-0141E. Public Service also filed for approval of a CPCN for the conversion of the Pawnee facilities in Proceeding No. 22A-0563E.

[52] Hrg. Exh. 302, Neil Answer Rev. 1, p. 36:8–44:17.

to the costs to the future securitization as approved for the net plant costs in Proceeding No. 22A-0515E. UCA estimated this deferral would decrease the revenue requirement in this Proceeding by $40 to $50 million.

98. In Rebuttal Testimony,[53] Public Service took no position on UCA's proposal but made several requests if the Commission were to grant the deferral. The Company emphasized that the unrecovered balances should continue to earn a return equal to the Company's WACC and sought clarification from the Commission that the depreciation expense was being deferred, not ceasing altogether, and that deferred amounts would be net of any applicable allowance for deferred income taxes. The Company also asked for a plan for future recovery of the deferred depreciation expense through retail rates and that the deferral be characterized as a mechanism intended to provide near-term benefits to customers. Public Service further requested to be afforded flexibility to modify the deferral and recovery in future proceedings.

99. The Settling Parties, except for Trial Staff, propose within the settlement filing an approach to the proposed Coal Plant Deferral. Public Service would record the deferral, including primarily the coal plant depreciation expenses, as a regulatory asset to be included in rate base, earning a return at the WACC established in this rate case until the balances are securitized or until the Commission authorizes amortization of the net plant values for the assets and those balances have been fully amortized. The balance of the regulatory asset would be added to the net plant amounts in a bundled securitization as part of the future financing application under Public Service's Clean Energy Plan and coal cost recovery settlements. If the Coal Plant Deferral is approved, Public Service's total retail revenue requirement decreases from $97 million to $48 million, assuming the Settlement Agreement is approved without modification.

[53] Hrg. Exh. 144, Moeller Rebuttal, p. 7:1–15:11.

100. Trial Staff opposes the Coal Plant Deferral, citing four concerns:

1) The proposal is a significant departure from ratemaking principles, including the principle that rate base plant reflects plant in service and is used and useful;
2) The record has insufficient evidence as to how the proposal would work and its impact on future rates;
3) There is potential for inter-generational inequity because current rate payers would not pay for an asset they are using, leaving cost recovery to future ratepayers when the plants have retired; and
4) The proposal is an inappropriate response to affordability concerns.

101. Trial Staff argues that the Coal Plant Deferral is different from the agreement reached in Proceeding No. 22A-0515E because, with this proposal, ratepayers would stop paying for the assets while they remain in service. Trial Staff also argues that unlike in Proceeding No. 22A-0515E, the record here does not include analyses and options for the treatment of cost recovery.[54]

102. Trial Staff contends that UCA's proposal was based on a hope that Public Service would provide annual costs to support the proposal, but Public Service has not provided any analysis, modeling, or workpapers that could be used for evaluation of the proposal, specifically with regard to projected rate impacts, net present value, the extent of plant balance growth, and the impact of using average rate assumption method or alternative methods, or other possible recovery paths.

103. In its SOP, Trial Staff underscores the ambiguity of how the proposal would work by noting that, initially, Trial Staff understood the expense deferral to be comparable to a credit card, with the expense set aside for payment later while it earns a WACC, but at hearing, the Company described instead a scenario where depreciation would freeze for the duration of the

[54] Hrg. Exh. 809, O'Neill Settlement, p. 15:6–13.

deferral. Trial Staff notes this would mean the Company would not be depreciating the assets, so there would be no depreciation expense to defer.[55]

104. Citing inter-generational inequity issues, Trial Staff also raises concern that future ratepayers would be required to pay for assets from which they never received service, which Trial Staff questions is in the public interest.[56]

105. Trial Staff acknowledges that affordability is a high priority concern but argues that there are many unknowns about future utility rates. Trial Staff notes that future ratepayers will be paying for the $2 billion being invested in the Colorado Power Pathway and the potential $5 billion investment resulting from Public Service's current Electric Resource Plan in addition to the non-coal-plant costs included in the test year in this Phase I rate proceeding. Trial Staff contends it is not possible to know what costs future ratepayers will have to bear and that deferring additional costs is not appropriate.[57]

106. Finally, in its SOP, Trial Staff objects that, with this proposal, the Company does not reduce base rates, but instead reduces rates today while moving those costs to future ratepayers to pay in full, with current ratepayers paying the WACC return on a higher rate base balance. Trial Staff concludes that this amounts to Public Service receiving the benefit of the WACC return while shifting all risk to future ratepayers.[58]

107. In Settlement Testimony, UCA maintains that deferring costs of the retiring coal plants offers a unique opportunity for the Commission to reduce rates. UCA contends that because future ratepayers will enjoy cost and environmental benefits of the retired plants, allowing current

[55] Trial Staff SOP, p. 14.
[56] Hrg. Exh. 809, O'Neill Settlement, p. 16:9–16.
[57] *Id*., p. 18:6–19:24.
[58] Trial Staff SOP, p.15.

ratepayers rate relief is appropriate compensation for helping to "jumpstart" the state's decarbonization efforts.[59] UCA argues that relief for current ratepayers is more important than long-term costs and that the Coal Plant Deferral better aligns the cost retiring coal plants with the costs and environmental benefits of the retirements.[60]

108. Public Service contends there are not inter-generational recovery concerns with the deferral because the Company will be making significant investments in the clean energy transition, to the benefit of both current and future customers. Since future customers will benefit, Public Service asserts they should bear some of the costs associated with early retirement of coal plants. Furthermore, the Company adds, securitization will mitigate some of the rate impact.[61]

109. The Company also maintains the record is sufficient to support the proposal, as long as no modification is made to the Settlement Agreement on this issue, including the impacts on the Settlement Agreement revenue requirement.[62] Public Service contends the Commission will have flexibility in future proceedings to maintain or modify the deferral, as long as the deferrals are recovered consistent with Public Service witness Moeller's rebuttal testimony. Public Service maintains the proposal balances the Company's need for certainty of recovery at WACC while maintaining the Commission's flexibility in future proceedings.[63]

2. Findings and Conclusions

110. Although the Coal Plant Deferral is a creative option intended by its proponents to address concerns about immediate affordability of utility bills, we agree with Trial Staff that,

[59] Hrg. Exh. 305, Pereira Settlement, p. 17:6–17.
[60] *Id*., p. 20:12–20.
[61] Hrg. Exh. 150, Berman Settlement, p. 31:9–16.
[62] Hrg. Exh. 151, Freitas Settlement, Attachments APF-31(a) and APF-31(b).
[63] Hrg. Exh. 150, Berman Settlement, p. 32:4–20.

without supporting documentation and workpapers from the Company, there is not sufficient evidence on the record for us to find the proposal is in the public interest. We are particularly disappointed that the parties supporting the Coal Plant Deferral failed to provide any meaningful net present value benefit/cost analysis into the record. While the contemplated securitization might help mitigate some amount of deferred costs in the future, the record has no evidence or analysis to support the necessary findings.

111. We also agree with Trial Staff that capital requests made by the Company for distribution system upgrades to support transportation electrification and climate adaptation, infrastructure improvement, and wildfire mitigation, among others, are likely to continue for the next decade. Future capital spending thus undermines, at least in part, the views offered by certain proponents of Coal Plant Deferral regarding the affordability of utility bills over time. As such, we have significant concerns about affordability issues over time, particularly in terms of natural gas prices, which we anticipate may continue or increase in volatility, given ongoing stresses of global conflict and extreme weather. The record does not contain any analysis of the escalation of future costs nor provide any framework through which such an analysis could be done.

112. Furthermore, we struggle with the arguments that the financial costs of the existing coal plants should be borne by future ratepayers, who will likely be experiencing the brunt of the environmental impacts from the previous operation of those and other facilities, when the initial development and operation of those plants were supported by some of the parties who are now supporting the Coal Plant Deferral.

B. Transmission Cost Adjustment

1. Initial Filings

113. Through its 2023 TCA filing on November 1, 2022, the Company sought to increase its TCA rate for calendar year 2023, effective January 1, 2023. Public Service's 2023 TCA revenue requirement comprised a projected 13-month average net transmission plant not yet included in base rates and year-end 2022 transmission CWIP. Because the TCA builds year-upon-year between Phase I electric rate cases, the 2023 TCA would have collected approximately $17.8 million more than the 2022 TCA, or $40 million total.

114. Trial Staff protested the 2023 TCA filing, contending that the Company requests recovery of costs associated with projects that are not extension or construction of transmission facilities and, as such, the costs are not eligible for recovery through the TCA pursuant § 40-5-101(4), C.R.S., which was enacted in 2007 as part of Senate Bill 07-100, enacted and effective March 27, 2007 (the TCA Statute).

115. In its protest, Trial Staff challenged the inclusion of small transmission projects the Company described in its filing as "Replacement of Existing Facilities." Trial Staff argued these projects do not constitute "construction" or "expansion" of transmission facilities, as required by statute but instead are capital projects associated with ongoing maintenance of the transmission system. Trial Staff also argued, based on a plain language reading of § 40-5-101(4), C.R.S., the TCA is to be used for the recovery of the costs a utility prudently incurs in planning, developing, and completing the construction or expansion of transmission facilities for which the utility has been granted a certificate of public convenience and necessity (CPCN), or for which the Commission has determined no CPCN is required, but is not intended as a catchall to recover costs associated with the replacement of existing facilities.

116. Trial Staff further pointed to Decision No. C22-0438, issued August 2022 in Proceeding No. 22M-0005E, that declined to grant the Company's request for a finding that certain projects "will be conducted in the ordinary course of business." According to Trial Staff, the Commission determined that annual utility reports submitted pursuant to Commission Rule 3206, 4 CCR 723-3, are intended only for the construction or transmission facilities and are not the vehicle for the Commission to render an "ordinary course of business" finding for other types of transmission projects.

2. Trial Staff's Position

117. Trial Staff points to a "troubling trend over the last fifteen years" of Public Service including significant routine replacement and repair of transmission infrastructure costs in its TCA revenue requirements.[64] Trial Staff calculates the Company's TCA revenue requirement has increased from $4.5 to $40.9 million, from 2009 to the present, with a majority of that increase accounted for by repair- and replacement-type transmission facility investments.[65] Trial Staff asserts, going forward, the Commission needs to determine a minimum of relief to which utilities are entitled. Trial Staff contends, given the currently high energy burden for Colorado ratepayers, a minimum of relief will be the desired outcome for the Commission.[66]

118. Trial Staff recommends the Commission revisit its interpretation of the TCA Statute to reflect more accurately what it claims to be the clear legislative intent of Senate Bill 07-100, that is, the promotion of *new* construction and expansion of transmission facilities in consideration of renewable generation, and not a direct substitution for recovery of routine repair and

[64] Trial Staff SOP, p. 3.
[65] *Id*., p. 16:9–17:2.
[66] *Id*., p. 23:1–24:19.

replacement through a rate case. Trial Staff argues the TCA Statute intended to provide an incentive to utilities, in the form of expedited recovery, to invest in additional transmission. According to Trial Staff, Public Services does not need to be incentivized to repair and replace failing equipment because of the ongoing obligation it already has to maintain a reliable transmission system.

119. Trial Staff contends that Senate Bill 07-100 was only intended to incent new construction or expansion of the transmission system in or near energy resource zones.[67] Trial Staff argues the phrase "construction and expansion of transmission facilities" is used in the context of transmission facilities located in or near energy resource zones.[68] Trial Staff maintains the legislative declaration makes clear the purpose of Senate Bill 07-100 was to encourage or incentivize utilities to improve the transmission to meet Colorado's electric needs. Trial Staff argues only subsection (c) of the declaration provides actionable language, while subsections (a) and (b) merely provide generic policy statements from the legislature about Colorado's electric system and its belief in the importance of a robust electric transmission system. Trial Staff argues, in contrast, the use of the word "therefore" in subsection (c), and the instructional language, "should continually evaluate," provides the legislative directive to action. Trial Staff states the logical conclusion it draws is the bill is intended to incentivize transmission investment that the utilities would not otherwise make. Trial Staff claims it is implausible that the legislature intended the ordinary churn of replacement of equipment that has failed or reached the end of life to be

[67] *See* § 40–2–126(1)(a), C.R.S., defining "energy resource zone" as a "geographic area in which transmission constraints hinder the delivery of electricity to Colorado consumers, the development of new electric generation facilities to serve Colorado consumers, or both. Subsection (2)(a) of this statute requires Colorado electric utilities to designate energy resource zones within the state.

[68] Hrg. Exh. 806, Camp Answer, p. 10:1–13:9.

entitled to cost recovery incentives. Trial Staff states, rather, it is only reasonable to expect utilities would make such routine investments, without incentives, to maintain reliability.

120. Trial Staff asks the Commission to establish in this Proceeding a new framework to determine project recovery eligibility under the TCA and puts forth a proposed three-pronged framework of authorization, expansion, and prudency for consideration.[69]

121. Regarding "authorization," Trial Staff states TCA eligible costs would be associated with projects for which the Company has received a CPCN or for which the Commission has determined does not require a CPCN. Trial Staff goes on to state projects completed in the ordinary course of business should not be eligible for recovery through the TCA.

122. Trial Staff suggests a project should only be considered "expansion" if it allows for the injection of new generation capacity to the utility's grid. According to Trial Staff, when "replacement" is the primary purpose of a transmission project, the Commission should not consider the project as "expansion."

123. And for prudency, Trial Staff recommends the Commission engage in ongoing monitoring to determine if projects are on time and within budget via a performance indicator. Trial Staff suggests this process include a requirement that a utility: (a) complete 95 percent of its scheduled work; and (b) demonstrate the annual ratio of the percentage of work completed to the percentage of actual spend to budget for each project equals or exceeds 95 percent of the project budgeted amount. If a project does not satisfy these requirements, Public Service may pursue transmission project cost recovery in its next rate case but will be unable to recover costs for the

[69] Hrg. Exh. 807, Gribb Answer, p. 15:1–25:21.

ineligible project using the TCA. Trial Staff concludes that without such a framework, intervenors may expend valuable resources to evaluate future TCA proceedings.

124. Trial Staff further states, if the Company is no longer entitled to forward-looking TCA recovery, the Company would experience a one-year lag between incurring costs and their recovery since the TCA operates on a yearly basis. Trial Staff asserts this is a minimal delay and necessary to ensure costs are borne by those ratepayers that benefit from the expense. Trial Staff concludes Public Service fails to recognize some regulatory lag is necessary to sufficiently address the question of prudence.

3. CEC's Position

125. CEC asks the Commission to order Public Service to restructure its TCA to eliminate any forward-looking cost recovery and thus to better align the TCA with ratemaking practices in Colorado. CEC argues that if the TCA is redesigned to recover only prudently incurred costs that have actually been incurred at the time the TCA rate goes into effect, on January 1st of each year, customers would only be paying rates that reflect the cost of transmission assets that are already in service. CEC contrasts that to the situation where, with a forward-looking TCA, customers rates reflect both the costs of existing facilities that have been brought into service, as well as the costs associated with facilities that the Company anticipates bringing online and putting into service in the upcoming year. CEC argues that, for at least a portion of every year, customers will be paying higher rates due to the costs of facilities that are not yet in service and that if there is a delay in a transmission line coming into service such that its in-service date is pushed into a subsequent calendar year, customers could be paying rates including the costs of a line not yet in service for over a year. Finally, CEC argues that accelerated recovery associated with an annual, historic mechanism is more than sufficient to provide a powerful incentive for Public Service to

build all of the transmission necessary and appropriate to accomplish Colorado's clean energy transition.

4. UCA's Position

126. UCA's advocacy in this case focused on total project costs over time, using the High Point Substation project, a joint transmission/distribution project as a representative example. Its estimated cost (combined transmission/distribution) increased from $3.1 million in Public Service's 2018 Rule 3206 Report to $37.6 million in the current consolidated proceeding. UCA witness Neil contends this project illustrates a pervasive issue of cost increases. He also advocates that, using the High Point Substation project for illustration, Public Service's annual Rule 3206 reports should include distribution costs, not only transmission costs, pointing out distribution costs for the High Point Substation to constitute more than one-half of total project costs.[70]

5. Public Service's Position

127. Public Service requests the Commission maintain the Company's existing TCA and decline to adopt Trial Staff's and CEC's recommended modifications to the scope and structure of its existing tariff.

128. As to its existing TCA, Public Service states its TCA was first approved in Decision No. C07-1085, Proceeding 07A-339E and the Commission's decision specifically included the phrase "repair, replacement, and modification of existing facilities … of the transmission system."[71] Public Service notes, in 2015, the Commission approved revisions that changed the TCA to a forward-looking rider to recover projected transmission costs.[72] In its 2014 Phase I

[70] Hrg. Exh. 302, Neil Answer, p. 13:1–15:5.

[71] Hrg. Exh. 125, Flores Supplemental Direct, p. 14:1–6.

[72] *Id*., p. 14:11–15:2; *see also* Proceeding No. 14AL-0660E, Decision No. C15-0292 (issued Mar. 31, 2015) (approving settlement agreement and establishing rates).

electric rate proceeding (Proceeding No. 14AL-0660E), the Company proposed to modify its calculation of the transmission costs in the rider to use a fully projected 13-month average net transmission plant for the year in which the TCA will be in effect. In its answer testimony, Trial Staff there testified the modification was "not prohibited by statute" and agreed with the modification subject to slight changes to assure no double counting of transmission costs in both transmission plant and CWIP. As part of the Commission's approval of a settlement resolving the case, the Commission granted Public Service approval to recover projected transmission investments. Public Service states the Commission has not issued any other decisions since 2007 to alter the types of transmission investments it may recover. Public Service concludes the Commission has therefore already ruled on this question.

129. As to the statutory language in § 40-5-101(4), C.R.S., Public Service contends the plain reading of the statute imposes three requirements to recover costs through the TCA: (1) costs must be prudently incurred for "planning, developing, and completing" a transmission facility; (2) the project must be for the "construction or expansion" of transmission facilities; and (3) the project must have either been granted a CPCN or the Commission determined none is CPCN. Public Service maintains the intent of Senate Bill 07-100 was both expansion of and continued investment in the existing transmission system.[73] Public Service contends the legislative purpose was to support utilities who developed and improved transmission to meet state renewable goals to meet the challenge of ensuring adequate transmission capacity for new renewable generation after the passage of the renewable portfolio standard. Public Service maintains the legislative declaration, which speaks to the critical nature of an overall robust transmission system, the importance of continued availability of reliable electricity, and the need to encourage utilities to

[73] Hrg. Exh. 121, Berman Supplemental Direct, p. 38:7–21.

improve the infrastructure as required to meet the state's energy needs, evidences the legislature's intent to encourage both maintaining existing infrastructure as well as adding new capacity.[74] The Company concludes Senate Bill 07-100 addressed the needed transmission investment by requiring utilities to designate areas where transmission constraints hinder development of resources or energy delivery as "energy resource zones," to develop plans for construction or expansion of transmission facilities consistent with the timing of renewable energy development, and to submit plans and applications for CPCNs for such facilities. The Company states the rate adjustment mechanism enacted in the bill was intended as a new cost recovery mechanism for transmission investments.

130. Regarding Trial Staff's proposed framework, Public Service argues that none of Trial Staff's three prongs should be adopted. It states the problems with each component range from being unnecessary or unworkable, to being fundamentally inconsistent with the plain language of the TCA Statute and prior Commission decisions. For example, with respect to authorization, the Company argues there is no need for the Commission to make determinations of TCA eligibility every year upon receiving TCA filings or in any other forum. Public Service adds is unclear how Trial Staff's proposed authorization prong is intended to work in practice. For example, it is unclear how the Company would seek a Commission determination for TCA eligibility prior to including projects in its TCA. Public Service also characterizes the prudency prong as a robotic application of actual results to arbitrary schedule and cost targets that does nothing to assess whether the costs of a transmission project were prudently incurred. The Company further argues that Trial Staff's prudence test is based on no legitimate, verifiable statistical process.

[74] Public Service SOP, p. 8.

131. Finally, as to forward-looking or current cost recovery, Public Service argues the purpose of a cost recovery rider such as the TCA is to provide more timely recovery of costs than would be achieved through a rate case in order to incentivize certain investments. According to Public Service, by allowing utilities to recover the costs of transmission investments more quickly through the TCA, the TCA encourages and facilitates these investments. Public Service further argues that modifying its TCA to only allow recovery of historical transmission investments would create a misalignment between the Company's investments and costs, which would in turn directly impact the Company's financial integrity by introducing additional regulatory lag to the Company's recovery of prudently incurred costs. Public Service that there are also safeguards in place in the TCA, in the form of an annual true-up, in the event that the Company's forecasted transmission investments do not match actual investments.

132. Public Service also points to a series of previous Commission decisions that support current recovery of costs through the TCA through the use of forecasts. Among those decisions is the order approving the settlement agreement and granting a CPCN for the Colorado Power Pathway in Proceeding No. 21A-0096E. Public Service suggests that modifying the Company's TCA to prohibit current cost recovery would be a material change to the Commission-approved settlement agreement in that case, as well as a departure from prior Commission TCA decisions.

6. Findings and Conclusions

133. Public Service's TCA is set forth in the Company's electric tariff, Colorado P.U.C. No. 8, in Sheet Nos. 142 through 142C. Sheet Nos. 142 and 142A implement the rate-schedule specific applicable charges that go into effect each year on January 1. The charges on Sheet Nos. 142 and 142A are developed based on the terms of the TCA on Sheet Nos. 142B and 142C. Sheet No. 142B states that the Company's TCA "reflect[s] the ongoing capital costs associated with

transmission investment that are not being recovered through the Company's base rates." The tariff defines the "Transmission Cost" to be recovered each year through the TCA as the projected increase of the 13-month average "net transmission plant" for the year the TCA will be in effect.

a. 2023 TCA Issues

134. By approving the Settlement Agreement, we resolve the 2023 TCA as proposed by the Settling Parties. We therefore authorize Public Service to include in its compliance tariff filing as required by this Decision modified Sheet Nos. 142 and 142A to set forth the rate-schedule specific applicable charges to collect the incremental 2023 TCA forecast, as filed on November 1, 2022, though December 31, 2023, in accordance with the terms of the Settlement Agreement.

b. Going-Forward Adjustment to Scope of TCA-Eligible Projects

135. The "Transmission Cost" recovered each year through the TCA as the projected increase of the 13-month average of the Company's net transmission plant satisfied the minimum requirements of Senate Bill 07-100 and Colorado statutes. As explained below, while we reject Trial Staff's argument that § 40-5-101(4), C.R.S., limits the meaning of the terms on Sheet No. 142B, we are persuaded by Trial Staff's advocacy in this Proceeding that it is necessary to modify the TCA beginning with the 2024 TCA by limiting the eligibility of the costs recovered through the TCA to capital costs associated with transmission investment that results in a net increase in transmission capacity, thereby excluding replacement and repair projects.

136. As an initial matter, the Commission indeed ruled as a matter of first impression in prior Proceeding No. 07A-339E, where it first approved a TCA for Public Service, that Public Service should recover all incremental transmission costs through its TCA rider.[75] At that time,

[75] *See* Proceeding No. 07A-339E, Decision No. C07-1085 at ¶ 19 (issued Dec. 24, 2007) (approving application to implement a transmission cost adjustment rider pursuant to recently enacted Senate Bill 07-100).

the entirety of the Commission's analysis on this issue was "that the plain language of § 40-5-101(4), C.R.S., does not contemplate differentiating between transmission investment made in the ordinary course or incremental investments. Simply the only restriction placed on the recovery of costs is with regard to facilities that the utility has been granted a [CPCN] or for which the Commission has determined that no CPCN is required."[76] So it is true that the Commission has addressed the meaning of the TCA statute, but that does not settle the issue that Trial Staff has raised. The Commission cannot ignore legal arguments presented to it simply because it has addressed them in the past. As it is before the courts, parties may argue that the Commission erred in its previous interpretation of the law. Because Trial Staff has presented us with a robust legal argument to that effect, we once again examine the statutory language in § 40-5-101(4), C.R.S., to determine whether the legislature intended to entitle utilities to extraordinary recovery for all incremental transmission costs.

137. Where the public interest may be adversely affected, the Commission is not bound by prior decisions. The fact the Commission makes its decisions based on the record of each case is precisely why the Commission is not bound by prior decisions or by any doctrine similar to *stare decisis* in its decision-making. Recognizing that Commission decisions are based on the record of each case, the Colorado Supreme Court has instructed "while consistency in administrative rulings is considered essential, and while agency rulings are entitled to great weight in subsequent proceedings … the appearance of arbitrariness is dispelled when new findings are made, as they

[76] Proceeding No. 07A-339E, Decision No. C07-1085 at ¶ 19 (issued Dec. 24, 2007).

were here, on the basis of new evidence and a new record."[77] This is particularly true when the Commission is examining utility rates, which is legislative in nature.[78]

138. Here, Trial Staff has persuaded us that now is an appropriate time to revisit this issue. Specifically, Trial Staff testified that both the total dollar amount recovered through Public Service's TCA and the portion of eligible projects that constitute repair- and replacement-type projects have increased since we first approved Public Service's TCA in 2007.[79] As well, the size of the TCA is set to accelerate sharply over the next few years as over a billion dollars in costs from the Colorado Power Pathway project flow into the rider for projects to build new transmission lines and build and expand substations. In addition, throughout this case we have heard from the public and many of the parties that it has become more challenging to afford utility service in this economic climate. We also heard through UCA's testimony that costs for approved projects often increase significantly from the planning stage to project completion. These developments, particularly the size of the TCA, the portion of projects constituting repair- and replacement-type projects, and the economic strain on ratepayers, shed new light on the importance of the differences among the various types of projects Public Service seeks recovery of through the TCA.

139. After considering the arguments and evidence put forth in this Proceeding, the Commission makes the following findings and conclusions.

140. First, that the provisions in § 40-5-101(4), C.R.S., do not prescribe the total body of projects that the Commission could determine to be eligible for recovery through Public

[77] *Colorado-Ute*, 198 Colo. at 541, 602 P.2d at 865.

[78] *See, Pub. Serv. Co. of Colo. v. Pub. Utils. Comm'n*, 26 P.3d 1198 (Colo. 2001) (the making of rates to govern public utilities is legislative in nature and not a judicial function); *Colorado-Ute*, 198 Colo. at 540–41, 602 P.2d at 865 (due to the legislative character of ratemaking, the Commission is not bound by its prior decisions or by any doctrine similar to *stare decisis*).

[79] *See* Proceeding No. 07A-339E, Decision No. C07-1085 (issued Dec. 24, 2007) (approving Public Service's application to implement a transmission cost adjustment rider pursuant to recently enacted Senate Bill 07-100).

Service's Commission-approved TCA. Instead, the statute sets the "floor" for what must be recovered through this type of mechanism, but the utility may propose, and the Commission may allow, a broader scope of projects to be eligible for this cost recovery.

141. Second, we find good cause to depart from our prior findings regarding interpretation of the TCA Statute, based on this more robust examination of the statutory terms in context and our understanding of the distinction between various types of transmission investments. As set forth below, we find the statute's plain language in § 40-5-101(4), C.R.S., stating a utility is entitled to recover through a rate adjustment mechanism the costs it prudently incurs "in planning, developing, and completing the construction or expansion of transmission facilities" reasonably excludes repair- and replacement-type projects, as Trial Staff has advocated. We reach this conclusion using the following analysis:

142. In the absence of an industry-specific term of art, we look to the plain language of the statute when ascertaining legislative intent and give the words and phrases their plain and ordinary meanings.[80] If the language is unambiguous, we look no further.[81] In so doing we must read the statutory scheme as a whole, "giving consistent, harmonious, and sensible effect to all of its parts."[82] We read words and phrases in context and construe them literally according to common usage unless they have acquired a technical meaning by legislative definition.[83] If the language is ambiguous, we may resort to other aids in statutory construction, including the legislative declaration and the consequences of various constructions.

[80] *See Montezuma Valley Irrigation Co. v. Bd. of Cnty. Commissioners of Cnty. of Montezuma*, 2020 COA 161, ¶ 19.
[81] *Id*. (citing *People v. Yascavage*, 101 P.3d 1090, 1093 (Colo. 2004)).
[82] *Colorado Prop. Tax Adm'r v. CO2 Comm., Inc.*, 2023 CO 8, ¶ 22.
[83] *Yascavage*, 101 P.3d at 1093; §§ 2–4–101, 2–4–212, C.R.S.

143. The parties have briefed this issue and pointed to other parts of the section, other sections, and the legislative history in support of their interpretations of "construction" and "expansion." But in our view the most instructive language, which comes just before these terms in subsection 4(a), describes the statutorily eligible costs as those costs the utility prudently incurs in: "*planning*, *developing*, and *completing* the construction or expansion of transmission facilities" (emphasis added). By limiting recoverable costs to those related to planning, developing, and completing the construction or expansion of transmission facilities, the legislature indicated it was contemplating larger scale projects that necessarily require planning and development. This is in contrast to, as Trial Staff would put it, the ordinary churn of replacement of equipment that has failed or reached the end of its useful life.[84] The legislature's inclusion of these descriptive terms indicates it intended for eligible projects to be those that required planning, developing, and completing, which we interpret to plainly exclude repair- and replacement-type projects. Finally, we note that throughout the revised statutes the legislature distinguishes between the terms "repair," "replacement," and "construction."[85] We conclude, had the legislature intended to include repair and replacement as eligible costs, it could have used those words in this statute as it had many times in the past. It did not.

[84] *See, e.g.*, Hrg. Exh. 806, Camp Answer, p. 19 (Trial Staff arguing it is implausible the legislature intended the ordinary churn of replacing equipment required cost recovery incentives and rather it is reasonable to expect utilities would make such routine investment without incentives in order to maintain reliability).

[85] *See, e.g.*, §§ 23–71–122 ("construct , erect, repair, alter, and remodel buildings and structures"); 24–30–1310 (funding for capital construction); 25–25–107 ("to acquire, construct, reconstruct, renovate, replace, alter, improve, maintain, repair, operate, lease as lessee or lessor..."); 35-46-111(1)(a) (road authority must "adequately construct, maintain, or repair right-of-way" fencing); 40–2–115(1)(d)(II)(A) (usage in Title 40–utilities–"Qualifications and verifiable credentials for personnel engaged in pipeline construction, inspection, and repair activities").

144. Moreover, the plain and ordinary meaning of the terms "construction" and "expansion" supports this reading. "Where the statute does not specifically define key terms, we look to the plain and ordinary meanings of the words, aided by the dictionary definition(s)."[86]

145. The common usage of *constructing* and *expanding* refers to creating something new or increasing the size of something, not to simply repair, replace or otherwise restore something to its original condition. For example, if someone were to say they were constructing or expanding a garage, it would be unreasonable to understand that they were simply replacing the garage door opener. Thus, by excluding repair and replacement type projects are we are giving the statutory terms their commonly accepted meanings instead of a strained or forced interpretation that would equate construction and expanding to the act of maintenance.

146. Dictionary definitions support this reading. Both Black's Law Dictionary[87] and Merriam-Webster[88] offer definitions for "construction" that would exclude repair or maintenance type of work. Both definitional chains at their core refer to building something from various components or parts. This general idea stands apart from replacing individual components within the transmission system. In our view, when transmission projects are undertaken for replacement or repair, nothing new is being built or constructed, and therefore those types of projects—while important—find no home in the language of the TCA statute, § 40-5-101(4), C.R.S. Similarly, while Black's offers no definition for "expand" or "expansion," Merriam-Webster defines

[86] *People v. Grosko*, 2021 COA 28, ¶ 18 (noting that plain language analyses can be aided by dictionary definitions where the statute does not specifically define key terms).

[87] Construction. Black's Law Dictionary. "The act of building by combining or arranging parts or elements; the thing so built." Black's does not define "build" or the verb "building".

[88] Merriam-Webster defines "construction" as "the process, art, or manner of constructing something", and the verb "construct" to mean "to make or form by combining or arranging parts or elements**:** build." Merriam-Webster Dictionary, https://www.merriam-webster.com/dictionary/construction, https://www.merriam-webster.com/dictionary/construct.

expansion as "the act or process of expanding; an expanded part; something that results from an act of expanding."[89] That same dictionary defines expand as "to increase the extent, number, volume, or scope of."[90] Interpreting *expansion* in this way accords with the purpose of the statute because both the electrical capacity and the physical reach of the transmission system are measured, and it can be easily understood whether a given project increases transmission capacity or the physical reach of the system itself.

147. Public Service suggests reading the two terms this way is impermissible because it would render "expansion" superfluous. Not so. If construction entails building new parts of the system, expansion refers to increasing system capacity. An example of expansion would be replacing power lines with those rated for higher power flows, also known as reconductoring. The physical footprint of the transmission system would not increase, but the capacity of the system has increased, which would constitute expansion. Similarly, certain substation upgrades that increase capacity should be considered expansion.

148. We are unpersuaded by the parties' references to the legislative declaration of Senate Bill 07-100. We have not found this statute to be ambiguous and therefore we will not turn to the legislative declaration.[91] Even if we were to find the statute is ambiguous and then resort to tools of statutory interpretation, including legislative history and purpose, we would reach the same result. We agree with Trial Staff's position that the legislative declaration, read as a whole, conveys that the purpose of Senate Bill 07-100 was to encourage or incentivize utilities to promptly and

[89] Merriam-Webster Dictionary, https://www.merriam-webster.com/dictionary/expansion.

[90] Merriam-Webster Dictionary, https://www.merriam-webster.com/dictionary/expand.

[91] *See* § 2–4–203(1)(g), C.R.S. (identifying the legislative declaration or purpose as an aid in construing ambiguous statutes); *People in Interest of T.B.*, 2016 COA 151M, ¶ 42 (noting that courts generally do not consider a legislative declaration where a statute is unambiguous and that a legislative declaration cannot override a statute's language); *McDonald v. People*, 2021 CO 64, ¶ 20 (explaining, where a statute is ambiguous, courts turn to other interpretative aids to discern the legislature's intent, including a statute's declaration or purpose).

efficiently improve their transmission to meet Colorado's existing and future needs. The bill's focus on building new transmission into energy resource zones comports with the legislative intent evinced by the plain language, revealing a focus on incentives for new build, not quicker cost recovery for maintenance and repair done in the ordinary course. As Trial Staff reasonably points out, the other generic policy statements in the declaration simply provide the narrative introduction necessitating the legislative action. And the words the legislature used in its declaration are not carried over in any way to subsection 4(a). We find no reason to deviate from the ordinary and commonly accepted meanings of these terms simply because of general statements made in the legislative declaration.

149. Third, and finally, we turn to the question of how best to implement this change in this Proceeding. As Trial Staff pointed out in testimony, Public Service's TCA revenue requirement has increased significantly since the rider was first approved, with a majority of that increase accounted for by repair- and replacement-type investments.[92] Consequently, we find the public interest would be better served by shifting away from extraordinary rider recovery for this subset of projects, which we have found in our discussion above is *not* required by statute. We find it appropriate, both as a legal and policy matter, and as part of the overall balance associated with approving the revenue requirement portion of the Settlement Agreement, for Public Service to seek to recover these maintenance costs through the ordinary means of rate cases. This will ensure the TCA primarily promotes new construction and expansion of transmission facilities including, for example, the development of the Colorado Power Pathway approved for construction in accordance with a comprehensive performance incentive mechanism in Proceeding

[92] Trial Staff SOP, p. 16:9–17:2.

No. 21A-0096E.[93] In sum, based on the record in this Proceeding, we find good cause on a going forward basis to exclude some of the additional projects that we previously allowed to be recovered through this rider by defining the transmission projects eligible for recovery through the TCA in the Company's TCA tariff as those that result in a net increase in transmission capacity.

150. Accordingly, we modify Sheet No. 142B of Public Service's Colorado P.U.C. No. 8 – Electric Tariff to specify that only the costs of qualified TCA projects are recovered through the rate adjustment mechanism. The specific changes to the TCA tariff language are set forth in Appendix B to this Decision. In November 2023 when Public Service files an advice letter to change the charges set forth on Sheet Nos. 142 and 142A for effect January 1, 2024, the Company shall also file a revised Sheet No. 142B for effect January 1, 2024, as required by this Decision.[94]

c. Evaluation of Other Adjustments to TCA Scope and Structure

151. We are also persuaded by the advocacy of Trial Staff, UCA, and CEC regarding the merits of reexamining other policies governing cost recovery of transmission investments. However, we are not inclined to make additional adjustments to Public Service's TCA based on the record in this Proceeding. We instead conclude that a full examination of whether cost recovery of TCA eligible investments should remain forward-looking for Public Service and of other cost recovery issues, such as material changes in cost estimates over time and determinations of the prudency of incurred transmission costs, is best done in a future rulemaking or in a separate set of

[93] Proceeding No. 21A-0096E, Decision Nos. C22-0270 (issued June 20, 2022) and C22-0430 (July 22, 2022).

[94] Public Service shall file the 2024 TCA in accordance with the Commission's rules governing advice letter filings. Sheet No. 142B included in the advice letter filing to implement the 2024 TCA shall reference this Decision, whereas Sheet Nos. 142 and 142A will not reference this Decision as the new charges have not yet been calculated and noticed to customers and thus have not been reviewed by the Commission.

utility-specific proceedings in the interim, which would allow for a more fully developed record on potential outcomes of any changes to the timing of TCA cost recovery.[95]

V. CAPITAL COST CONTAINMENT

152. We reluctantly approve the inclusion of the costs of the Cabin Creek Facility Project as allowed by the Settlement Agreement, but we emphasize that in the holistic prudence review of the Cabin Creek Facility Project pursuant to the settlement previously approved in Proceeding No. 22A-0345E, as referenced in the Settlement Agreement at Section C., we expect a full discussion of accountability for outages and the inclusion in rate base of costs associated with outages. At hearing, witnesses from the Company, Trial Staff and UCA all indicated that they expected the holistic prudence review process referenced in the Settlement Agreement would be an appropriate venue for evaluating the inclusion of the resource in rate base, in addition to a review of other performance and capital expenditure-related topics. This discussion should form a roadmap of how extended outages will be handled in the future for company-owned resources. Given the difficulties of holding the Company financially accountable for the outages of the Cabin Creek Facility through after-the-fact prudency review, going forward, in Public Service's ongoing Electric Resource Plan, Proceeding No. 21A-0141E, we expect to evaluate a more comprehensive approach regarding performance, timing, and cost containment issues to achieve a fair and balanced approach when addressing new Company owned assets as compared to assets owned by independent power producers and that better aligns customer and utility incentives.

[95] At its weekly business meeting on April 19, 2023, the Commission orally adopted a decision opening a pre-rulemaking proceeding to examine potential modifications to the Commission's Rules Regulating Electric Utilities, 4 CCR 723-3, related to the development, construction, and cost recovery of transmission infrastructure. The Commission directed the staff of the Commission to work with stakeholders and other interested participants to elicit and compile responses to questions and to compile proposed rule changes for the development of a future Notice of Proposed Rulemaking (NOPR).

153. We also note the testimony of UCA witness Neil,[96] highlighting cost overruns of some $200 million as against the initial estimates. Given these hundreds of millions of dollars in cost overruns, we find that after-the-fact prudence reviews have struggled to align incentives between the utility and customers and that new ways will likely be needed to effectively mitigate these overruns. These can also be addressed through performance incentive mechanisms and other actions in Public Service's Electric Resource Plan. Specifically, metrics must be established for capital costs, operations cost, availability, and timing.

VI. ORDER

A. The Commission Orders That:

1. The tariff sheets filed by Public Service Company of Colorado (Public Service) on November 30, 2022, with Advice Letter No. 1906-Electric are permanently suspended and shall not be further amended.

2. The tariff sheets filed by Public Service on November 1, 2022, with Advice Letter No. 1902-Electric are permanently suspended and shall not be further amended.

3. The Joint Motion to Approve Settlement Agreement filed on June 20, 2023, by Public Service is granted, consistent with the discussion above. The Settlement Agreement is approved, as modified by this Decision. A copy of the Settlement Agreement is attached to this Decision as Appendix A.

4. Public Service shall file an advice letter compliance filing to modify the tariff sheets in Colorado PUC No. 8 Electric Tariff consistent with the findings, conclusions, and directives in this Decision. Public Service shall file the compliance tariff sheets in a separate proceeding and on not less than one business days' notice. The advice letter and tariff sheets shall be filed as a

[96] Hrg. Exh. 302, Neil Answer Rev. 1, p. 8:1–13.

new advice letter proceeding and shall comply with all applicable rules. In calculating the proposed effective date, the date the filing is received at the Commission is not included in the notice period and the entire notice period must expire prior to the effective date. The advice letter and tariff must comply in all substantive respects to this Decision in order to be filed as a compliance filing on shortened notice.

5. Public Service shall modify Sheet No. 142B of its Colorado PUC No. 8 Electric Tariff for its TCA for effect January 1, 2024, in accordance with this Decision, consistent with the discussion above.

6. The 20-day period provided for in § 40-6-114, C.R.S., within which to file applications for rehearing, reargument, or reconsideration, begins on the first day following the effective date of this Decision.

7. This Decision is effective upon its Mailed Date.

B. ADOPTED IN COMMISSIONERS' WEEKLY MEETINGS
August 16, 2023 and September 6, 2023

(S E A L)

ATTEST: A TRUE COPY

Rebecca E. White,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK

MEGAN M. GILMAN

TOM PLANT

Commissioners