Decision No. C25-0183

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO**

PROCEEDING NO. 24AL-0275E

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IN THE MATTER OF ADVICE LETTER NO. 871 FILED BY BLACK HILLS COLORADO ELECTRIC, LLC TO INCREASE BASE RATE REVENUES, TO IMPLEMENT REVISED BASE RATES FOR ALL RATE SCHEDULES, AND OTHER TARIFF REVISIONS EFFECTIVE JULY 15, 2024.

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# COMMISSION DECISION PERMANENTLY SUSPENDING TARIFF SHEETS, ESTABLISHING NEW BASE RATES, AND REQUIRING FILING OF COMPLIANCE TARIFF

Issued Date: March 17, 2025
Adopted Date: February 12 and 19, 2025 and March 5 and 12, 2025

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# I. BY THE COMMISSION

## A. Statement

1. On June 14, 2024, Black Hills Colorado Electric, LLC, doing business as Black Hills Energy ("BHCOE" or "Black Hills" or the Company"), filed Advice Letter No. 871 ("Advice Letter 871") with tariff sheets to revise base rate revenue for all electric service in the Company's Colorado P.U.C. No. 11 Tariff, along with certain other changes to its tariff.

2. By this Decision, the Commission permanently suspends the effective date of the tariff sheets filed with Advice Letter No. 871 and orders BHCOE to file compliance tariffs with new base rates for retail gas service consistent with the findings and conclusions in this Decision.

## B. Background

### 1. Advice Letter No. 871

3. On June 14, 2024, BHCOE filed Advice Letter No. 871 with supporting attachments and pre-filed testimony of 13 witnesses as a combined Phase I and Phase II rate

proceeding.[1] The proposed effective date of the tariffs filed with Advice Letter No. 871 was July 15, 2024.

4. This is the first Phase I electric rate case filed by BHCOE since 2016.[2] The Company contends that its existing rates do not cover its current cost of providing electric service. BHCOE states that the Company is seeking the revenue increase because its service area has not seen the same economic growth that the rest of Colorado has enjoyed and that even though the number of the Company's residential customers has increased, use per customer has decreased, largely because of net metering.[3] Additionally, Commercial and Industrial sales have remained flat since the Company's 2016 Phase I Rate Case. At the same time, the Company has experienced higher operating costs and has made investments in its electric system. Specifically, the Company states that it has invested $371 million since the 2016 Phase I Rate Case and plans an additional $99 million in 2024.

5. In its Direct case, BHCOE requested to increase the base rates it charges its customers for electric service, increasing its base rate revenue by $36,760,812 above its current base rate revenue of $179,706,763. In its Direct case, BHCOE calculated its revenue requirement at $216 million, based on a Current Test Year ("CTY") ending December 31, 2024, and using year-end rate base valuation. On Rebuttal, the Company revised its request to utilize a historic test year ("HTY"), and revised its revenue requirement request to $25,143,517, based on a total revenue requirement of $204,845,955.

[1] The Commission ordered that BHCOE's next rate case be a combined Phase I/Phase II filing in Decision No. C16-1140 at ¶ 204 issued in Proceeding No. 16AL-0326E on December 16, 2016.

[2] Proceeding No. 16AL-0326E ("2016 Phase I Rate Case").

[3] The Company states that some 10 percent of its Direct Testimony request of $37 million revenue increase results from losses due to net metering. While the BHCOE does not have a specific request with regard to net metering, it provides an informational CCOSS demonstrating the cost shifting effect of net metering and suggest that Colorado should re-visit its net-metering statutes.

6. BHCOE initially calculated its proposed revenue requirement on a weighted average cost of capital ("WACC") of 7.3372 percent, comprising a return on equity ("ROE") of 10.50 percent and a cost of debt at 4.61 percent, and a capital structure of 52.75 percent equity and 47.25 percent debt. However, on Rebuttal, the Company revised its request to include a WACC of 7.36 percent, with a capital structure of 52.66 percent equity and 47.34 percent long-term debt, and an ROE of 9.83 percent.

7. The proposed revenue increase reflects the roll-in to base rates investments currently being recovered through the Clean Air Clean Jobs Adjustment ("CACJA"), Transmission Cost Adjustment ("TCA"), and Purchased Capacity Cost Adjustment ("PCCA"). Additionally, BHCOE proposes new deferred tracking mechanisms for property taxes, insurance expense, rate case expense, PUC Administration fees and greenhouse gas fees, vegetation management, and a Customer Communication and Education Plan to inform customers of changes resulting from this rate review proceeding.

8. The Company also proposes a new depreciation study, noting that its last study was completed in 2011 in Proceeding No. 11A-387E. The result of BHCOE's new study is an increase of $3.6 million over the previous total depreciation expense of $32.4 million.

9. Regarding Phase II requests, the Company notes that because the Company's last class cost of service study ("CCOSS") was based on demand measured in 2015, there has been a significant load shift from the Commercial rate class to the Residential rate class, such that in this Proceeding, Residential customers would see a 26 percent increase in rates per its direct case. In order to mitigate this increase, the Company proposes a uniform increase across all rate classes; with its initial filing the BHCOE proposed a 20.46 percent increase across all rate classes, relieving the Residential class of some $5 million in cost responsibility. On Rebuttal, the Company modified

this proposal to a 13.99 percent uniform increase across all rate classes, reflecting the Company's reduced revenue requirement as presented in Rebuttal Testimony.

10. BHCOE's initial proposed rate increase results in a monthly bill impact of $20.14 (18.0 percent) increase for Residential customers and $25.06 (10.0 percent) increase for Small General Service customers. The Company's Rebuttal Testimony would result in a monthly bill impact of $15.11 (13.8 percent) increase for Residential customers and a $23.03 (9.5 percent) increase for Small General Service customers. While BHCOE currently has an inclining block rate structure for its Residential rate class, the Company proposes replacing this rate structure with a flat energy rate. BHCOE also requests on Rebuttal an increase to its residential fixed customer charge from $8.77 to $9.00 per month.

11. In the same manner, the Company proposes to change the billing determinants for Large General Service and Large Power rate classes from a tiered rate to a structure of monthly charge, demand charge, and energy charge.

12. Additionally, BHCOE proposes an update of its time of use ("TOU") tariffs and making these available to all rate classes as an optional service. BHCOE proposes TOU rates at a 2:1 on-peak/off-peak ratio, with on-Peak hours from 4:00 p.m. to 8:00 p.m. on weekdays.

### 2. Procedural History

13. BHCOE filed the Direct Testimony of 13 witnesses in support of its request. As part of this testimony and in compliance with Rule 3109(e) of the Commission's Rules Regulating Electric Utilities, 4 *Code of Colorado Regulations* ("CCR") 723-3, the Company included a graph illustrating the ten-year trend of its rates[4] and details of its rate trend report.[5]

[4] Hr. Ex. 101, Harrington Direct, p. 18:13.
[5] Hr. Ex. 113, Ahrens Direct, Attach. DSA-4.

14. By Decision No. C24-0489, issued on July 9, 2024, the Commission set the tariff sheets filed with Advice Letter No. 871 for hearing and suspended their effective date to November 12, 2024, pursuant to § 40-6-111(1), C.R.S., and certified the completeness of BHCOE's initial filing, in accordance with § 40-3-102.5(1)(b), C.R.S. and Rule 3109(f) of the Commission's Rules Regulating Electric Utilities, 4 CCR 723-4.[6]

15. By Decision No. C24-0581-I,[7] issued on August 13, 2024, the Commission addressed the requests for intervention in this Proceeding and established the parties. The parties include: Staff of the Colorado Public Utilities Commission ("Staff"); the Colorado Office of the Utility Consumer Advocate ("UCA"); the City of Pueblo, County of Pueblo, and Pueblo Economic Development Corporation (collectively, "Pueblo"); Energy Outreach Colorado ("EOC"); Laborers International Union of North America Local 720 ("Local 720"); Colorado Solar and Storage Association and the Solar Energy Industries Association (jointly, "COSSA/SEIA"); Board of Water Works of Pueblo, The Fountain Valley Authority, and Colorado Springs Utilities/Southern Delivery System (collectively "Public Utility Intervenors"); Western Resources Advocates/Sierra Club (jointly, "WRA/Sierra Club or "WRA/SC"); City of Cañon City and City of Florence (jointly, "Cañon City/Florence"); Holcim (U.S.), Inc. ("Holcim"); and Electrify America, LLC ("Electrify America").

16. Additionally, through Decision No. C24-0581-I, the Commission further extended the suspension date of the tariff sheets filed with Advice Letter No. 871 for an additional 130 days to March 22, 2025, pursuant to § 40-6-111(b), C.R.S.

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[6] In Proceeding No. 23R-0408EG, the Commission adopted temporary administrative rules to implement the rate case filing requirements enacted in Senate Bill 23-291, effective August 7, 2023; these rules became permanent in Commission Proceeding No. 24R-0410E. The applicable "certification rule" for electric utilities is Rule 4 CCR 723-3-3109(f).

[7] Decision No. C24-0581-I was initially issued in error as Decision No. C24-0580-I. An Errata correcting that error issued on August 20, 2024.

17. In WRA/Sierra Club's motion for permissive intervention, they requested the Commission order BHCOE to file supplemental direct testimony regarding a voluntary heat pump rate consistent with § 40-3.2-110(2), C.R.S. WRA/SC noted that the statute requires the heat pump rate to be filed by August 1, 2027, but stated that this is "very likely" the only general electric rate case that will be filed before that date, thus this is the appropriate venue for the Company to propose a heat pump rate.

18. In its Protest, filed on June 20, 2024, UCA requested the Commission order BHCOE to produce an HTY for the 12 months ending December 31, 2023. Through Decision No. C24-0581-I, the Commission granted UCA's request.

19. Through Decision No. C24-0581-I, the Commission directed the Company to file supplemental direct testimony. The Commission required the Company to file supplemental direct testimony addressing a rate forecast through 2040 that incorporates the information provided by the Company in its most recent investor presentation for Colorado, including base rate revenue requirements and total revenue requirements, and the associated projected overall average rates and residential rates, as well as addressing UCA's request for a HTY presentation. The Commission declined to order supplemental direct testimony as requested by WRA/Sierra Club on a voluntary heat pump rate pursuant to § 40-3.2-110(2), C.R.S., finding that the Company is aware of the 2027 filing requirement and that the timeframe for providing such a filing in this Proceeding is too short.

20. Through Decision No. C24-0581-I, the Commission referred to an administrative law judge ("ALJ") discovery disputes and future motions seeking extraordinary protection of information claimed to be highly confidential.

21. Through Decision No. C24-0608-I, issued on August 21, 2024, the Commission established a procedural schedule with filing deadlines, hearing dates, and provisions governing discovery. Decision No. 24-0581-I established the dates for the evidentiary hearing as December 2 through 6 and December 9 through 11, 2024.

22. Through Recommended Decision No. R24-0619-I, issued on August 27, 2024, the Motion for Protective Order Affording Extraordinary Protection and Request for Temporary Waiver of Rule 1101(b)(VII) to Provide Public Versions of Certain Workpaper Attachments filed by BHCOE on June 14, 2024, was partially granted. Through Recommended Decision No. R24-0619-I, the Company's Second Motion for Protective Order Affording Extraordinary Protection for Highly Confidential Information filed on August 6, 2024, was granted.

23. On August 16, 2024, COSSA/SEIA filed a Motion to "Strike and/or Dismiss" testimony related to BHCOE's statements regarding net metering as one cause of the Company's revenue requirement deficiency.

24. On August 28, 2024, BHCOE filed Supplemental Direct Testimony in response to Decision No. C24-0581-I.

25. On August 30, 2024, BHCOE filed its Response to Motion to Strike and/or Dismiss Testimony and Empirical Evidence Regarding Net Metering-Caused Revenue Deficiency and Cost Shifts Between Customers.

26. Through Decision No. C24-0669, issued on September 17, 2024, the Commission declined to strike or dismiss the Net Metering Materials from this Proceeding and denied COSSA/SEIA's Motion.

27. Through Recommended Decision No. R24-0685-I, issued on September 24, 2024, the remaining requests for extraordinary protection of highly confidential information in the

Motion for Protective Order Affording Extraordinary Protection and Request for Temporary Waiver of Rule 1101(b)(VII) to Provide Public Versions of Certain Workpaper Attachments filed by BHCOE on June 14, 2024, were granted.

28. Through Decision No. C24-0701-I, issued on September 28, 2024, the Commission scheduled hearings on October 29 and 30, 2024 in Pueblo, Colorado and on November 19, 2024, in Cañon City, Colorado, for the purpose of taking comment from members of the public.

29. Through Decision No. C24-0701-I, the Commission also scheduled a remote hearing on December 5, 2024, for the purpose of taking comment from members of the public.

30. In accordance with the procedural schedule established by Decision No. C24-0608-I, Answer Testimony was filed by Staff, UCA, Cañon City/Florence, COSSA/SEIA, Electrify America, EOC, Public Utility Intervenors, Pueblo, and WRA/Sierra Club on October 11, 2024.

31. On October 18, 2024, Staff, UCA, and Pueblo filed a Joint Motion Pursuant to Electric Rule 3109(f)(III)(D), and Request for Expedited Response Time of Five Business Days ("Joint Notice Motion"), raising concerns regarding the Customer Notice issued by Black Hills on June 14, 2024, in conjunction with its advice letter filing in this Proceeding.

32. On October 21, 2024, Black Hills filed a Corrected Customer Notice and indicated it would provide formal response to the Joint Notice Motion within the response time approved by the Commission.

33. Through Decision No. C24-0775, issued on October 24, 2024, the Commission shortened response time to the Joint Notice Motion.

34. Through Decision No. C24-0817, issued on November 12, 2024, the Commission denied the Joint Notice Motion, in part, and required BHCOE to file an updated, accurate customer notice containing details of its Rebuttal Case.

35. On October 29 and 30, 2024, the Commission held hearings in Pueblo, Colorado to take public comments, as scheduled by Decision No. C24-0701-I. Approximately 45 members of the community spoke in Pueblo over the two-day period.

36. BHCOE filed its Rebuttal Testimony on November 8, 2024. BHCOE presented a recalculation of its proposed base rate revenue increase, lowering it from about $37 million to about $26 million.

37. Staff and EOC filed Cross-Answer Testimony on November 8, 2024.

38. On November 19, 2024, the Commission held hearings in Cañon City, Colorado to take public comments, as scheduled by Decision No. C24-0701-I. Approximately 15 members of the community spoke in Cañon City.

39. By Decision No. C24-0881, issued on November 27, 2024, the Commission excused Electrify America, LLC from the evidentiary hearing in this Proceeding.

40. The evidentiary hearing was held remotely before the Commission *en banc* on December 2, 3, 4, 5, 6, 2024 and December 9, 2024. At the start of the evidentiary hearing, the Commission admitted all pre-filed testimony and attachments into the evidentiary record as contained on Hearing Exhibit 1400.[8] During the course of the hearing, the Commission admitted additional hearing exhibits that were offered by parties during their cross-examination or re-direct

[8] Hr. Ex. 1400 included the testimony referenced in BHCOE/Staff's Motion for Approval of its Stipulation with Trial Staff Regarding a Quality of Service Plan. Therefore, despite being included on Hearing Exhibit 1400, all of Marianne Ramos' Answer Testimony (Hr. Ex. 505 and attachments), as well as the QSP applicable part of Fiona Sigalla's Answer Testimony (Hr. Ex. 500 at 31:15-18 and one line on Table FDS-7). And portions of the Harrington and Wolf rebuttal testimonies: Hr. Ex. 116 at 8:21 and 84:4-91:6 and Attachment MJH-16; and Hr. Ex. 117 at 14:9-16:19, are not part of the evidentiary record in this Proceeding.

of witnesses. The Commission entered at hearing exhibits: 1400 (including its contents); 110, Attach. DNH-8, Rev. 1; 118 SKJ-14 (WP 54); 123 (WP 68, Rev. 1); 126; 127; 133; 134; 135; 141; 142; 144; 145; 146; 149; 150; 153; 155; 156; 161 (administrative notice); 162; 163; 164C; 165C; 166C; 167C; 168C; 169C; 170C; 171C; 172C; 178 (administrative notice of Commission files); 187; 189; 197; 199; 200 (administrative notice of Commission files); 202; 302, Attach. CWS-41; 311; 316; 320; 321; 322; 323; 324 (administrative notice of Commission files); 325 (administrative notice of Commission files); 326 (administrative notice of Commission files); 327; 328 (administrative notice of Commission files); 329; 330; 331; 332 (administrative notice of Commission files); 336; 335; 338; 340; 343; 404; 405; 412; 413; 415; 416; 418; 419; 420; 424; 425; 426; 500, Attach. 18; 500, Attach. FDS-28; 501, Attach. ETO-10C; 511 (Response 31-6 only); 512; 514; 514HC; 516HC (and public slip sheet); 517; 519; 603; 1103, 1104, 1105, 1106; 1107; 1109; 1110; 1111; 1500; 1501.

41. On December 9, 2024, the Commission held a remote hearing to accept public comments as scheduled by Decision No. C24-0701-I. The oral comments generally expressed concern that utility bills continue to increase and requested that the Commission decline to grant additional rate increases.

42. On December 3, 2024, BHCOE filed a Motion for Approval of its Stipulation with Trial Staff Regarding a Quality of Service Plan (“QSP”).

43. Through Decision No. C25-0020, issued on January 10, 2025, the Commission granted a motion by BHCOE to allow all parties a 60-page limit for statements of positions (“SOPs”) in this Proceeding.

44. Post-hearing SOPs were filed on January 10, 2024, by BHCOE, Staff, UCA, Cañon City/Florence, COSSA/SEIA, EOC, Public Utility Intervenors, Pueblo, and WRA/SC.

45. The Commission deliberated at the February 12 and 19, 2025 and March 5 and 12, 2025 Commissioners' Weekly Meetings ("CWMs").

46. Through Decision No. C25-0122-I, issued on February 21, 2025, the Commission scheduled a technical conference on March 3, 2025. BHCOE was directed to update its COSS and CCOSS and to design new base rates to replace those on the tariff sheets filed with Advice Letter No. 871 based on oral deliberations on February 12 and 19, 2025, and to file the updated COSS, CCOSS, and proposed rates by February 28, 2025. The Company was also directed to file an updated Sheet No. 71 of its Demand Side Management Cost Adjustment ("DSMCA") in accordance with the changes in projected sales revenue resulting from the final decision in this Proceeding.

47. Through Decision No. C25-0139-I, issued on February 27, 2025, the Commission denied the Motion Requesting an Additional Day of Hearing for the Technical Conference filed by Staff on February 21, 2025.

48. At the technical conference on March 3, 2025, overseen by ALJ Segev, BHCOE presented modifications to its COSS and CCOSS to reflect the oral decisions the Commission made during its deliberations on February 12 and 19, 2025. The Company also presented base rate values for each of its customer classes based on the modified COSS and CCOSS.

49. Through Decision No. C25-0166, issued on March 7, 2025 the Commission denied WRA/Sierra Club's Motion to Supplement the Filings Ordered by Decision No. C25-0122-I and declined to require the Company to file an updated COSS and CCOSS to reflect a voluntary heat pump rate.

50. The Commission concluded its deliberations to adopt this Decision at the Commissioners' Weekly Meeting on March 5 and 12, 2025. The Commission reviewed the results of the Technical Conference held on March 3, 2025, as part of those deliberations.

51. In addition to the public comments provided orally at the public comment hearings, the administrative record for this Proceeding includes more than 900 additional written public comments generally opposing any rate increase and raising concerns over the quality and value of service provided by BHCOE. Commenters express that they cannot afford higher utility bills and that the communities served by BHCOE in Colorado already struggle to attract new businesses, a problem which would be exacerbated further by higher electric rates.

## C. Discussion, Findings, and Conclusions

### 1. Overall Findings on Establishment of New Rates

52. The updated cost of service studies, rates, and bill impacts filed by BHCOE on February 28, 2025 and presented by the Company at the March 3, 2025 Technical Conference lead us to conclude that the base rates established by this Decision will: (1) be sufficient to ensure safe and reliable service to BHCOE's electric customers; (2) allow BHCOE to secure adequate financing at a reasonable cost and to provide the Company with a reasonable opportunity to earn a return commensurate with the returns of other entities of comparable risk; and (3) are just and reasonable and non-discriminatory.

53. BHCOE proposed a base rate revenue increase of $25,143,517 in its Rebuttal Testimony. This decision establishes a base rate revenue increase of $17,031,520.

54. BHCOE filed and presented updated bill impacts corresponding to the recalculated base rate increase caused by the Commission's oral deliberations. The monthly Residential bill impact, using the Company's alternative rate mitigation of applying a 10.13 percent increase to all

rate classes except Large Power Transmission customers, resulted in a 6.7 percent increase for average use (*i.e.*, 600 kWh per month) customers.

### 2. Legal Foundation and Burdens of Proof

#### a. Burden of Proof and Record

55. As the party seeking Commission approval or authorization, BHCOE bears the burden of proof with respect to the relief sought;[9] intervenors bear the burden of proof with regard to any independent proposals advanced in Answer Testimony. The burden of proof is by a preponderance of the evidence.[10] A party has satisfied its burden under this standard when the evidence, on the whole, tips in favor of that party. The evidence must be "substantial evidence," which is defined as "such relevant evidence as a reasonable person's 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."[11] In rate cases, after the utility proposing a tariff change presents its case-in-chief, putting forth evidence to justify its requested rate increase, the burden of going forward shifts to intervenors who then have the opportunity to provide evidence either rebutting the proponent's evidence or supporting intervenors' own arguments. The Commission has an independent duty to determine matters that are within the public interest.[12]

[9] *See* Rule 1500, 4 CCR 723-1 (burden of proof and initial burden of going forward shall be on the party that is the proponent of a decision, *i.e.*, the regulated entity proposing a tariff change) and § 24-4-105(7), C.R.S. (proponent of order has burden of proof).

[10] *See* § 13-25-127(1), C.R.S. (burden of proof in any civil action shall be by a preponderance of the evidence).

[11] *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)).

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

### b. Duty and Authority to Set Rates

56. 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.[13] The Commission is an administrative agency of the legislature,[14] charged with the authority, and duty, to regulate the rates of public utilities operating within Colorado. Section 40-3-102, C.R.S., vests in the Commission the power to regulate all the 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. Article XXV of the Colorado Constitution affirms the General Assembly's power to regulate public utility facilities, service, and rates and charges, and delegates that power in all respects to the Commission. These principles of Colorado constitutional law are known as the "*Miller Brothers* Doctrine" pursuant to the holding in *Miller Brothers, Inc. v. Public Utilities Commission*,[15] that the Commission has as much authority as the General Assembly possessed prior to the adoption of Article XXV in 1954, unless and until the General Assembly enacts a specific statutory restriction on the Commission's authority, which then controls.

57. 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.[16] 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

[13] *Colorado-Ute Elec. Ass'n, Inc. v. Pub. Utils. Comm'n*, 760 P.2d 627, 638 (Colo. 1988); *see* §§ 40-3-101, 40-3-102, 40-3-111, and 40-6-111, C.R.S. (Commission is charged with ensuring that utilities provide safe and reliable service to customers at just and reasonable rates).

[14] 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.*, 178 P. 6, 10 (Colo. 1918).

[15] *Miller Bros., Inc. v. Pub. Utils. Comm'n*, 525 P.2d 443, 451 (Colo. 1974).

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

charged.[17] Section 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.

### c. Just and Reasonable Standard

58. As codified in state law, § 40-3-101(1), C.R.S., the rates and charges assessed for public utility service must be "just and reasonable." The Colorado Supreme Court has held the primary purpose of utility regulation is to ensure the rates charged are not excessive or unjustly discriminatory.[18] 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.

59. Under the just and reasonable standard, the Commission considers both the utility investors' interest in avoiding confiscation and the utility customers' interest in preventing exorbitant rates.[19] This requires the Commission to protect the public interest by ensuring 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 attract capital and 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 the right of consumers to pay a rate which accurately reflects the cost of service rendered and the right of the

[17] § 40-3-111, C.R.S.; *see CF&I Steel*, 949 P.2d at 584 (finding the Commission has a 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).

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

[19] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944); *Colo. Mun. League v. Pub. Utils. Comm'n*, 687 P.2d 416, 418 (Colo. 1984).

utility and its investors to earn a return reasonably sufficient to maintain its financial integrity.[20] The ratemaking function involves the making of pragmatic adjustments and there is no single correct rate.

### d. Holistic Ratemaking Process

60. One purpose of this Proceeding is to establish base rates, the most significant rates, and charges billed to a utility's retail customers. Base rates for electric service fund the bulk of the utility's investments in transmission and distribution infrastructure as well as its investments in meters, services, computer systems, and other equipment and facilities needed to provide natural gas service to consumers. Base rates thus provide utilities a substantial source of revenue to cover the costs of providing service. Base rates are also the mechanism by which utilities collect sufficient revenues to ensure financial soundness of the utility, provide a reasonable return to their shareholders, and to cover the costs of debt payments that finance the investments necessary to fulfill the utility's obligation to serve and meet regulatory standards of service consistency. The capital, operating, and financing costs to achieve these objectives are interrelated and themselves represent a balance of interrelated inputs to the determination of just and reasonable rates. As explained below, the combination of costs intended to be recovered through base rates form the basis for a calculated revenue requirement and represent an expected level of cash flow determined to be within a range necessary to meet these larger objectives.

61. As the Colorado Supreme Court has long recognized, "rate making is not an exact science," and when it sets rates, the Commission necessarily exercises judgment rather than

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

complete reliance on a mathematical or legal formula, to establish just and reasonable rates that balance the interests of both the utility investors and customers.[21]

62. While the Commission's decision must be based upon evidentiary facts, calculations, and known factors, it necessarily exercises much judgment in the findings and conclusions it makes based on the evidence when setting the final level of rates.[22] For example, as the Colorado Supreme Court has expressly identified, in setting an appropriate utility rate the Commission considers cost of service along with other factors which are rationally related to legitimate utility regulatory purposes.[23] As the Court reasoned, without such discretion, the Commission would "become a rubber stamp relegated to examining cost studies of utilities."[24]

63. In executing its duty to adopt rates that are fair and reasonable, the Commission is not limited to options formally presented by the parties.[25] So long as the findings of fact on which the rate is founded have a legally adequate basis in the evidence and pass the constitutional tests, the courts will not disturb the Commission's determination. In this inquiry, it is the result reached, not the particular rate methodology employed by the Commission, that determines whether a rate is just and reasonable.[26]

64. The Colorado Supreme Court has described the Commission's rate setting 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.[27] A rate

[21] *Pub. Utils. Comm'n v. Nw. Water Corp.*, 451 P.2d 266, 276 (Colo. 1963).

[22] *See Mountain States Tel. & Tel. Co. v. Pub. Utils. Comm'n*, 513 P.2d 721, 726 (Colo. 1973) (Commission must have before it evidence, but determining what is a just and reasonable rate is a matter of judgment or discretion).

[23] *CF&I Steel*, 949 P.2d at 588.

[24] *Id*. (quoting *Integrated Network Servs., Inc. v. Pub. Utils. Comm'n*, 875 P.2d 1373, 1383 (Colo. 1994)).

[25] *Integrated Network Servs.*, 875 P.2d at 1381.

[26] *Glustrom v. Pub. Utils. Comm'n*, 280 P.3d 662, 669 (Colo. 2012); *Colorado-Ute Elec. Ass'n, Inc. v. Pub. Utils. Comm'n,* 602 P.2d 861, 864 (Colo. 1979) (citing *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944)).

[27] *Colo. Mun. League v. Pub. Utils. Comm'n*, 473 P.2d 960, 971 (Colo. 1970).

that is neither so unreasonably low as to deprive the utility of its constitutional right of compensation nor too excessive so as to unjustly exploit customers should not be subject to revision. As the U.S. Supreme Court said in *Hope* years ago, "It is … the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry … is at an end."[28]

65. We reiterate these principles here to elucidate that our decision-making in this rate case inherently involves myriad interrelated legal conclusions, factual findings, and policy decisions—all of which contribute to our final determination of what constitutes just and reasonable rates. In addition to the consideration of mathematical figures and equations that the parties present to support targets for revenue collections from rates, we must evaluate the effect of many factors, exercising broad legislative discretion as well as regulatory expertise. To disturb one factor considered by the Commission in setting the final rates risks upsetting the careful balance achieved by the Commission. While the adjudicative process requires that we resolve specific contested issues raised by the parties, we approach each interrelated decision cognizant that, as the revenue requirement increases, so do rates, and thus each decision requires balancing of a fair return for the company with reasonable rates for customers. Given the interrelated nature of rate case decision-making, as long as the outcome results in *overall* just and reasonable rates, any attempt to reexamine, after-the-fact, a single building block of that end result endangers the balance of the entire rate structure.. The intricate nature of our task is precisely why the legality of the end result of ratemaking, and not the legality of each calculation or input, controls.[29] An isolated increase (or decrease) in rates based solely on one factor could unbalance and distort the

[28] *Hope*, 320 U.S. at 602.
[29] *Glustrom,* 280 P.3d at 669.

ratemaking structure. Consequently, reversal of a single issue may not necessarily lead to a change in rates as the Commission could very well determine that inclusion of the erroneous component did not cause the overall rates to be unjust or unreasonable. Or the Commission could determine that, in order to consider an adjustment, it must undertake a more comprehensive review re-examining other potentially affected elements of the revenue requirement target. The outcome would naturally depend on the specific characteristics of the issue and the reach of the reviewing court's ruling.

### 3. Affordability

66. Because BHCOE has not filed a rate case for some eight years, the impact of the proposed increases on ratepayers is particularly acute in this case. Additionally, BHCOE's service territory includes areas with a high percentage of income qualified customers, so any increase will be challenging for many BHCOE customers.

67. In addition to the comments received during the four public comment hearings, the Commission received more than 900 written comments. The comments reflected frustration of customers that they are struggling to make ends meet and cannot afford any rate increase. Some commenters explained that they work multiple jobs in order to pay their bills and many expressed concern that any increase to their electric bill would create financial hardship.

68. The written testimony of the Public Utility Intervenors, Cañon City/Florence, Pueblo, and UCA encourage the Commission to reject any rate increase in this Proceeding. Pueblo's witnesses testified how high retail rates adversely affect residential customers and is a leading reason that Pueblo has been unable to attract business development. Pueblo's witnesses also argued that the Company has poor community relations and that the Commission should deny any rate increase and establish a process through which Black Hills can

be sold to a larger utility. Specifically, Pueblo's witnesses note that of Colorado's 64 counties, Pueblo ranks 47th in per capita personal income at $47,208.[30]

69. Cañon City/Florence witnesses question whether the Company has done enough to assist businesses and residents to understand or reduce bills and point to reliability issues and a subsequent shift for one business to a different demand rate schedule.[31] Additional testimony asserts that while local businesses are concerned about the direct impact of a rate increase, they also worry that increased residential rates could put a damper on consumer spending, providing examples of two retailers who have declined to expand their businesses for this reason[32] and that the area overall is struggling to attract new investment because of high utility rates. If the Commission approves a rate increase, Cañon City/Florence suggest the Commission consider mitigation strategies such as disallowing distribution and transmission investments as imprudent, adopting the Company's parent entity's capital structure, or adopting Staff's ROE and revenue requirement deficiency recommendations. Alternatively, Cañon City/Florence contend that the Commission could deny the requested increase outright because the Company did not meet its burden because it failed to consider affordability and disproportionately impacted community impacts .[33]

70. UCA witness Schonhaut recommends the Commission make affordable rates the primary consideration in this rate case. Citing Governor Polis' February 2023 letter to utilities and governmental agencies regarding affordable energy and the Commission's Affordability Initiative Initial Work Plan[34] Ms. Schonhaut recommends the Commission reject BHCOE's proposed

[30] Hr. Ex. 403, Pueblo County Board of County Commissioners Answer, pp. 7:15 – 8:3.
[31] Hr. Ex. 1200, Hamrick Answer, pp. 10:18 – 11:8; 11:17 – 11:23.
[32] Hr. Ex. 1201, Harrmann Answer, p. 11:1– 11:11; Hr. Ex. 1200, Hamrick Answer, p. 7:16 – 7:20.
[33] Cañon City/Florence SOP at p. 10.
[34] Hr. Ex. 300, Schonhaut Answer, Attach. CZS-4.

increase.[35] She further asserts that it is unfair for customers who have been paying higher rates than the statewide average should not be subject to further rate increases. Denying a rate increase would "constitute effective regulation of BHCOE by the Commission that is in the public interest and consistent with the economic, environmental, and social values of the state."[36] Ms. Schonhaut notes that other UCA witnesses provide analysis and recommendations on specific aspects of the filings in this rate case that should be relied upon only if the Commission rejects her recommendations for no rate increase.[37]

71. In its SOP, UCA argues that BHCOE has demonstrated for eight years that it has operated successfully at current rates so no rate increase can be justified. Additionally, UCA contends that the Commission's Affordability Initiative resulting from the Commission's exploration of electric utility retail rates[38] serves as the foundation for considering affordability as critical to the Commission's review of the utilities it regulates.

72. In its Answer Testimony and its SOP, Staff also encourages the Commission to consider affordability in its decisions in this case, citing to Senate Bill ("SB") 21-272 and the Distribution System Planning statute, § 40-2-132.5, C.R.S., and case law.[39] Staff notes the Equity Initiative Capstone Report released in July 2024 concludes that utilities have a role in establishing affordable rates and that the Affordability Initiative's Initial Work Plan states "Affordability is a critical part of the Commission's oversight as it regulates Colorado gas and electric utilities." Staff also references a recent Commission decision in which the Commission found "…it is

[35] Hr. Ex. 300, Schonhaut Answer, p. 20:1 – 20:6.
[36] *Id.* at p. 27:16 – 27:18.
[37] *Id.* at p. 8:6 – 8:7.
[38] Proceeding No. 20M-0251E.
[39] *Public Utilities Commission v. District Court*, 527 P.2d 233 (Colo. 1975).

increasingly critical to consider each decision the Commission makes from the perspective of its impact on affordability."[40]

73. Through Rebuttal Testimony and at the evidentiary hearing, BHCOE rejects the arguments that the Company has a poor relationship with businesses in the community, noting that two of the largest companies in Pueblo, Holcim and CS Wind, are expanding. Furthermore, the Company notes that in addition to utility rates, businesses consider a number of factors when evaluating location, including proximity to an airport and to customers, housing, transportation costs, labor, infrastructure, government policies, and environmental considerations. The Company also states that its customer team is prepared to assist customers and that it offers a variety of options for bill payment.[41]

74. BHCOE recommends the Commission reject UCA witness Schonhaut's recommendations as unlawful, illogical, and inconsistent with utility ratemaking principles. The Company allows that affordability should be taken into account when the Commission sets rates, but it cannot be the only factor, as proposed by Ms. Schonhaut. BHCOE notes that UCA's other witnesses provide a reasoned and analytic approach to the rate review, consistent with ratemaking principles.[42] The Company also argues that rejecting a rate increase based solely on affordability concerns is illogical because doing so would negate any rate increase regardless of the Company's costs to provide service and attract capital to meet future expansion needs. BHCOE points to a case in West Virginia in which the West Virginia Public Service Commission determined that:

[40] Decision No. C23-0083 at ¶ 24 issued in Proceeding No. 19A-0369E on February 6, 2023.
[41] Hr. Ex. 124, Rodriguez Rebuttal, p. 14:3 – 14:16.
[42] Hr. Ex. 116, Harrington Rebuttal, pp. 20:8 – 21:18.

> Our role is to establish that lowest fair and reasonable level of rates and charges consistent with the costs to utilities of providing that service. To the extent that there are citizens of the State who may have difficulty paying for those services, the Commission attempts to ameliorate that impact within the authority granted to it by statute and Constitutional limitations by appropriate rate design, by encouraging the Legislature to address the underlying societal problem through encouraging and supporting utility rate support programs financed by taxpayers and to some extent ratepayers, by allowing charitable and public support for special rate and weatherization programs and, most importantly, by paying particular heed to the level of and propriety of the costs that the utilities include in their rates.[43]

75. In its SOP, BHCOE maintains that it has taken affordability into account in its Rebuttal Case by accepting a 2023 HTY and 13-month average rate base and lowering its requested ROE to 9.83 percent, leading to an $11 million decrease in its revenue requirement request.

76. We are acutely aware of the implication of authorizing a rate increase in BHCOE's service territory. While affordability is not a standalone issue in this case, consistent with the Commission's decision-making in every rate case, affordability forms the backdrop against which the Commission makes decisions related to revenue requirement and rate design. Ultimately, we generally agree with Staff's characterization of the affordability considerations: "Staff encourages the Commission to carefully consider each decision point in this Proceeding, particularly those impacting the overall cost of service, with the backdrop of affordability and reasonably priced service."[44] Affordability can and should be considered within each input of rates, however, it cannot be a justification to throw out or eliminate a rate increase entirely. However, neither UCA nor Pueblo have presented a compelling case that the Commission could legally reject the entire rate increase, nor have they shown that "no rate increase" is the best interest of customers. However, as we make decisions on discrete factors affecting rates, affordability is one of many

[43] Hr. Ex. 116, Harrington Rebuttal, p. 23:20 – 23:32, citing *In re Appalachian Power Co.,* 288 P.U.R. 4th 185, 2011 WL 2150661 (Mar. 30, 2011).

considerations we can utilize to determine, on balance, what is best for ratepayers and the Company.

77. We are unpersuaded by the advocacy of Cañon City/Florence, UCA, and others that claim the Company's filing must be rejected because it did not consider affordability when presenting its case. None of the laws cited change the constitutional standard here. The utility has a constitutional right to earn a return and recover costs, while the Commission must also ensure consumers pay a rate which accurately reflects the cost of service rendered, which is the standard we have applied throughout this Decision.

**4. Test year and valuation of rate base**

78. In its initial case BHCOE proposed a 2024 CTY ending December 31, 2024, with a 13-month average rate base valuation. In their Answer Testimonies Staff and UCA both recommended use of a 2023 HTY and a 13-month average rate base valuation. The Company agreed to a 2023 HTY and a 13-month average rate base in its Rebuttal Testimony and modified its COSS accordingly.

79. We find that use of a 2023 HTY and 13-month average rate base valuation is appropriate in this Proceeding.

**5. Cost of Capital**

**a. Return on Equity**

**(1) BHCOE's Position**

80. On Rebuttal, BHCOE requests a 9.83 percent ROE, down from an initial request of 10.5 percent. BHCOE based its recommendation on analyses applying the following model forms: discounted cash flow ("DCF"), capital asset pricing model ("CAPM"), and empirical CAPM (or

("ECAPM"). BHCOE's ROE witness, Mr. McKenzie, conducted these models based on a proxy group of comparable utilities based on six criteria, as well as a group of non-utility entities.

81. BHCOE argues there is "undisputed record evidence" that the Company's proposed ROE is "similar to that of other financially sound businesses having similar or comparable risks."[45] Black Hills contends a 9.83 percent ROE is consistent with the average authorized ROE for vertically integrated utilities for the twelve months ending September 30, 2024. The Company contends that using the recent national average ROE for vertically integrated utilities represents a conservative approach to estimating the cost of capital. As explained by Company Witness, Mr. McKenzie, the national average is a lagging indicator and likely understates what investors would expect given current market conditions.[46] He also notes that Treasury bond yields have risen dramatically since the Commission last set the Company's return in 2016, and that debt rates relevant to Baa-rated corporations have increased from 4.38 percent to 5.79 percent in that time frame.

82. Mr. McKenzie reminds the Commission that the Supreme Court established via two critical cases, *Hope*[47] and *Bluefield,*[48] that a just and reasonable ROE must be sufficient to 1) fairly compensate the utility's investors, 2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and 3) maintain the utility's financial integrity. Mr. McKenzie contends that, while the *Hope* and *Bluefield* decisions did not establish a particular method to be followed in fixing rates (or in determining the allowed ROE), these and subsequent cases enshrined the importance of an end-result that meets the opportunity cost standard of finance. Under this doctrine, the required return is established by investors in the capital markets based on expected

[45] BHCOE SOP at p. 17.
[46] *Id*. at pp. 17-18.
[47] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope*").
[48] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923) ("*Bluefield*").

returns available from comparable risk investments.[49] He also suggested that providers of debt and equity capital "place significant emphasis on maintaining strong financial metrics and credit ratings that support access to debt capital markets under reasonable terms. This emphasis on financial metrics and credit ratings is shared by equity investors who also focus on cash flows, capital structure and liquidity, much like debt investors."[50]

**(2) Positions of Intervening Parties**

83. Staff recommends a ROE value of 9.3 percent based on a range between 9.1 percent and 9.37 percent. Staff suggests the Company applied "statistically inappropriate" techniques to generate high model results including cherry-picking input data and eliminating "illogical results" to achieve favorable outcomes.[51] Staff calculated its range based on the constant growth and multi-stage DCF models and a proxy group of seven electric utilities.

84. Staff notes the Company's current authorized ROE is 9.37 percent and it has remained profitable since its last rate case in 2015. Staff notes that Black Hills raised its dividend for 53 consecutive years. Staff also points out that the Company's 2024 debt issuance was oversubscribed by roughly 5.5 times, indicating strong demand for the Company's securities. Given BHC's strong financial abilities, authorizing a ROE reflective of the limited risk the Company faces will not jeopardize Black Hills' relationship with the financial market.

85. Staff suggests the Company's operations represent very modest risk as roughly a third of its revenues are a direct pass-through of energy costs using the energy cost adjustment ("ECA") and another third is demand charges and customer charges that have little risk of

[49] Hr. Ex. 105, McKenzie Direct, p. 11.
[50] *Id.* at p. 12.
[51] Staff SOP at p. 31.

non-recovery. Staff also notes the Commission recently approved a 9.3 percent ROE for Public Service Company of Colorado ("Public Service").

86. UCA argues the record does not support the Company's requested 9.83 percent ROE, and setting ROE at UCA's suggested value of 9.3 percent will save ratepayers $2.5 million.[52] UCA also argues Black Hills' ROE calculations are plagued with problems including: 1) unrealistically high growth rates and equity risk premiums; 2) inappropriate adjustments to artificially increase estimated ROEs; 3) use of outdated data; 4) exclusion of results deemed to be too low; 5) ignoring the implications of market developments such as the Federal Reserve lowering interest rates; 6) selection of inappropriate companies as proxies; 7) use of a non-utility proxy group to justify high ROEs; 8) use of methodologies to estimate the ROE that have not been relied upon in Colorado and most other jurisdictions; and 9) the consideration of stock flotation costs.[53]

87. UCA notes that the Company's ROE witness did not conduct a MS-DCF analysis from which Mr. Fernandez produced a range of 9.3 to 9.7 percent. With respect to the cost of debt's relevance to equity returns, UCA argues that Federal Reserve reduced rates several times already and suggests Mr. McKenzie fails to include the full impact of those rate reductions.

**(3) BHCOE Response**

88. The Company suggests Staff's and UCA's analyses suffer from multiple errors and shortcomings. Specifically, Staff's witness Sigalla only utilized two versions of a single analytical model (*i.e.*, constant growth- and multistage-DCF model), despite acknowledging on cross-examination that the Commission looks to all models. BHCOE contends that with the reliance on a single analytical model, Staff's analysis includes no objective checks on

[52] UCA SOP at pp. 21-22.
[53] Hr. Ex. 303, Fernandez Answer, p. 19.

reasonableness.[54] Further, the Company contends, even though Ms. Sigalla conceded that her analysis included formula errors that would change her DCF projections by 43 basis points, she would not alter her recommendation. Ms. Sigalla also applied an "overly restrictive proxy group selection criteria." Overall, these shortcomings prove her recommendations are "unreliable"[55] according to BHCOE.

89. Black Hills argues UCA's proxy group was also suspect as UCA witness Fernandez did not follow his own selection criteria and excluded five utilities of comparable risk. Further, the Company suggests his analysis limited equity risk premium to historical rates of return, inaccurately reported the historical market risk premium as compared to his own source, relied on two highly questionable sources of projected Treasury bond yields, inaccurately included a lower 30-year treasury bond yield that what was within his cited source, and failed to reflect a size adjustment.[56]

90. With respect to bond yields, Black Hills contends that Witnesses Sigalla and Fernandez have ignored the following: (1) utility bond yields are 98 basis points higher than when the Commission authorized a 9.37 percent in BHCOE's 2016 Phase I Rate Case; (2) 10-year treasury bond yields are 190 basis points higher than in 2016; and (3) 30-year treasury yields are 149 basis points higher than in 2016. Despite conceding that bond yields and the cost of equity generally move in the same direction, both witnesses encourage the Commission to reduce Black Hills' ROE from that authorized in 2016. Black Hills contends that adjusting BHCOE's currently authorized ROE to reflect current bond yields would imply a cost of equity of 9.93 percent.[57]

[54] BHCOE SOP at p. 18.
[55] *Id.* at p. 19.
[56] BHCOE SOP at p. 19.
[57] *Id*. at p. 20.

91. At hearing, the Company's Mr. McKenzie agreed with several aspects of Commission examination. First, Mr. McKenzie agreed that BHCOE's parent company, Black Hills Corporation's ("BHC"), current stock price represents a dividend yield of approximately 4.15 to 4.5 percent, and when combined with BHC-suggested growth rates via investor presentations, total return on equity ranges from 8.15 percent to 10.15 percent.[58] Mr. McKenzie also agreed that the stock market is the final arbiter of stock value and expected return rather than models relying on forecasts and comparisons to proxy groups, though he suggested it was not appropriate to look at a single company in setting ROE. He also explained that the financial forecasts embedded in his models produce, in certain instances, significantly divergent results which required him to negate those results from his final calculations. Mr. McKenzie also admitted that his proxy group is comprised entirely, or nearly entirely, of holding companies that hold far higher debt ratios than operating companies such as BHCOE, and that such higher debt capitalization positions represent higher risk, all other things equal.[59] He also agreed Beta, one of the critical inputs to the CAPM and ECAPM models, was subject to material variability in the criteria applied and final calculation of Beta value.[60] This was represented through a wide range of potential Beta values applicable to Black Hills Corporation.

**b. Cost of Debt**

92. All parties agree to the Company's proposed 4.61 percent cost of debt.

[58] Hr. Tr. December 3, 2024, pp. 149:17 – 151:2.
[59] Hr. Tr. December 3, 2024, pp. 151:18 – 153:22.
[60] Hr. Tr. December 3, 2024, pp. 140:21 – 143:20.

### c. Capital Structure

#### (1) BHCOE's Position

93. BHCOE initially proposed a capital structure with 52.75 percent equity but revised that to 52.66 percent in its Rebuttal Testimony. When combined with proposed ROE and cost of debt upon Rebuttal, BHCOE requests a final WACC of 7.36 percent.[61]

94. The Company's witness, Mr. Stevens, explains that BHC provides financing for all of its utility subsidiaries, including BHCOE via: (1) assignment of debt through intercompany notes payable to BHC based on the weighted average cost of BHC's pool of senior unsecured debt; (2) wholly or partially retaining its own earnings; and (3) receiving equity infusions from BHC.[62] He also explained credit rating agencies evaluate financial integrity and the parameters they apply. He indicated that BHCOE does not maintain a separate credit rating since it does not issue its own securities but, like many other utilities, has faced challenges "due to rising inflation, extreme winter weather events, and geopolitical uncertainty."[63]

95. Mr. Stevens contends that BHCOE's capital structure as of December 31, 2023, was 52.66 percent equity and 47.34 percent long-term debt, and thus, that is the Company's "actual" capital structure, and that the value is very close to what was approved in the Company's 2016 Phase I Rate Case.[64] He also contends that it is the "Commission's well-established policy in utility rate cases is to adopt the actual capital structure used to finance the utility's regulated operations."[65]

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[61] Hr. Ex. 119, Stevens Rebuttal, p. 6.
[62] Hr. Ex. 104, Stevens Direct, p. 8.
[63] *Id*. at p. 14.
[64] Hr. Ex. 104, Stevens Direct, p. 17, citing Decision No. C16-1140 issued in Proceeding No. 16AL-0326E on December 19, 2016.
[65] Hr. Ex. 104, Stevens Direct, p. 17.

### (2) Positions of Intervening Parties

96. Staff suggests the Commission adopt a capital structure that represents 44.1 percent equity, consistent with the capital structure of BHCOE's parent, BHC. Staff notes that when BHCOE needs financing, it is BHC that interacts with the capital markets, and there are no BHCOE level metrics for financial integrity or credit ratings.[66]

97. Staff argues BHCOE intentionally leveraged itself to purchase SourceGas, the prior owner of the distribution assets and territory, which resulted in an overall increase of financing costs, as referenced in BHC's credit reports. Staff contends BHC is attempting to recover these costs through its operating companies including BHCOE.

98. Additionally, Staff argues that BHC is unfairly allocating debt and equity between subsidiaries and that Colorado regulated utilities were assigned higher equity ratios than that requested in other jurisdictions. Staff also notes that BHC's unregulated subsidiaries are financed with substantially more debt than regulated operating companies including BHCOE. Staff argues that is counter intuitive as the unregulated subsidiaries should be financed with *more* debt because unregulated entities are riskier than regulated entities that have some assurance of cost recovery.[67]

99. Initially UCA agreed with the Company's proposed capital structure, but in its SOP amended its position, endorsing Staff's recommendation of 44.1 percent equity. UCA states that Staff's analysis of capital structure results in a revenue deficiency that is several million dollars less than that which results from the capital structure applied in UCA's Answer Testimony.[68]

[66] Staff SOP at p. 27.
[67] Staff SOP at p. 29.
[68] UCA SOP at p. 20.

### (3) BHCOE Response

100. BHCOE rejects the capital structure proposed by Staff and UCA, citing the *Peoples Natural Gas v. Public Utilities Commission*[69] *("Peoples")* decision by the Colorado Supreme Court. Specifically, the Company argues that in *Peoples*, the Court instructed that "[u]nless it has been demonstrated by a substantial showing that rate payers are materially prejudiced the actual capital structure which finances utility operations, the PUC should use the actual capital structure in calculating rates." Black Hills also notes that *Peoples* emphasized that regulatory commissions should accord considerable deference to the judgment of utility management in regard to its capital structure.[70]

101. BHCOE argues there has been no showing of material prejudice as the proposed capital structure of 52.66 percent equity/47.34 percent debt "falls squarely within the range of capital structures approved for other utilities over the eight calendar quarters ending June 30, 2024, which shows an average equity ratio of 51.18 percent."[71] The Company also argues that the Commission lacks information to speculate on the correct capital structure and that the requested capital structure is consistent with prior authorized capital structures and the Commission consistently found the Company's 52.66 percent equity to be reasonable in each of the prior seven rate cases.

102. BHCOE also objects to the insinuation that the SourceGas acquisition negatively impacted the capitalization of BHCOE as unsupported in the record. BHCOE argues the Company maintained a roughly balanced capital structure at the time of the 2016 Phase I Rate Case and that is what is proposed today.

[69] *Peoples Natural Gas v. Public Utilities Commission*, 193 Colo. 421, 567 P.2d 377 (1977).
[70] *Peoples Natural Gas Division of Northern Natural Gas Co. v. PUC*, 567 P.2d 377, 379 (Colo. 1977), *citing Mountain States Telephone and Telegraph Co. v. PUC*, 182 Colo. 269 at 281-282.
[71] BHCOE SOP at p. 11.

#### d. Findings and Conclusions

103. We find that an overall WACC of 6.9 percent is consistent with the record, facilitates the Company's financial integrity, and will result in just and reasonable rates.

104. With respect to the Company's cost of debt, we note that the parties agreed on a long-term cost of debt of 4.61 percent. Given that it has been repeatedly recognized by the courts that ratemaking is not an exact science, and as Mr. McKenzie acknowledged at hearing,[72] the Commission finds it appropriate to round this value to 4.6 percent. We believe incorporating two decimal places to the value presumes a false level of precision when future debt issuances could readily be above or below the Company's embedded value.

105. With respect to the ROE, we authorize a range of 9.3 to 9.5 percent. We find this range to be consistent with the evidentiary record in this Proceeding. In particular, we note this range falls squarely in the stock market's valuation of BHC based on the current dividend yield plus the projected earnings the Company frequently and very recently represented to the investor community. While Mr. McKenzie's traditional ROE evaluation, representing a forward projection of a proxy group of other utilities, is illustrative, we believe the Company's actual dividend yield and projections of its own earnings to the investor community is far more instructive and, critically, assessed by the most important arbiter of value, the marketplace. We also point out that there was no analysis whatsoever of BHCOE's internal return on equity invested or debt credit metrics on this record, leaving the Commission with little visibility as to the Company's true financial health.

106. Further, we were persuaded by UCA's arguments that the Company's CAPM models inappropriately eliminated non-dividend paying stocks and included an irrelevant size adjustment. We also note, as Black Hills admitted at hearing, that the Beta value—critical to the

[72] Hr. Tr. December 3, 2024, pp. 163:11 – 164:17.

CAPM model—is subject to significant variance based on which economic forecasting firm's inputs are used and the criteria applied therein. Finally, we are troubled by the fact some results produced by Mr. McKenzie's CAPM and ECAPM models are simply ignored or continued into the calculation of average values, essentially eliminating much of the supposed precision leading up to that stage in the modeling process.

107. We also find that, as we have warned against generally in recent Public Service rulings, the Company conflates holding companies and operating companies. We agree with BHCOE's expert that DCF and CAPM models must necessarily be conducted on holding companies for which stocks are directly issued and priced. But operating companies generally maintain higher equity ratios, as we see here in the instant case. If the Company wants to rely on a proxy group of holding companies in the future, it should also suggest a reasonable adjustment to account for the specific capital structure it proposes relative to the entities that comprise the proxy group.

108. With respect to capital structure, we disagree with the Company's interpretation of the word "actual" as the currently practiced capital structure based on prior Commission decisions. Staff raised important questions as to the fairness of debt and equity allocation amongst BHC's regulated and unregulated subsidiaries, and the Company provided no specific analysis to support its capital structure proposal other than that is what was previously approved.

109. As suggested by the National Association of Regulatory Utility Commissioners (NARUC), we find the appropriate starting point for this discussion to be the capital structure which is "typically measured at the corporate level at which the utility actually interfaces

[with]…and [is] disciplined by the capital markets."[73] This approach also seems consistent with the *People's* decision where the court found that the holding company, Northern Natural Gas, was the entity with the "actual" capital structure. In that case, the court found "that it is within the power of the PUC to pierce corporate structures of corporations which also operate nonutility divisions or subsidiaries to impute a capital structure for the utility operation, which is reflective of the capitalization actually backing the utility operation." It is also an approach previously used by this Commission.[74] In the instant Proceeding, the holding company is similarly financing an array of utility and non-utility operations, painting a complex picture of capital allocation and potential subsidization across operating entities. Importantly, we find the *People's* decision affirms our view that the starting point for the capital structure calculation in this case should be the holding company.

110. That being said, we recognize that BHC capital structure of 44 percent equity/56 percent debt may fall outside the range of most electric utility operating companies. Accordingly, we believe it is necessary to exclude certain unregulated entities from the array of operations conducted under the BHC holding company structure.[75]

111. In summary, taking all of this into account, and recognizing that ratemaking is not an exact science, we find a common equity ratio of 47-49 percent, and thus 51-53 percent financed as long-term debt represents a reasonable adjustment to the holding company capital structure to determine the actual operating company holding structure, is likely to support the Company's

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[73] Hr. Ex. 1502, "A Cost of Capital Market and Capital Market Primer for Utility Regulators, prepared by NARUC for the U.S. Agency for International Development in April of 2020."

[74] *See* Decision No. C11-1373 at ¶ 103 issued in Proceeding No. 11AL-382E on December 22, 2011, ("We find that the capital structure used to establish rates in this proceeding should match the composition of funding acquired through long-term debt versus equity financing. We therefore reject Black Hills' proposed capital structure and adopt the holding company's capital structure as suggested by Staff. We find this capital structure has a realistic relationship to the marketplace, which is where capital will be raised.").

[75] Specific data held confidential (*See* Hr. Ex. 500HC, Attach. FDS-24).

financial integrity, and facilitate the BHC's ability to raise capital. We find this range also represents an approximate mid-point between the Company and Staff's proposals, and reasonably balances customer affordability and the Company's ability to raise capital as necessary to meet its energy delivery obligations. We authorize a WACC of 6.9 percent and allow BHCOE's management discretion, consistent with *Peoples*, to utilize capital structures within the allowed ranges to balance financial stability and return to its shareholders as it deems appropriate.

**6. Contested Cost of Service Issues**

**a. LM6000**

**(1) Roll into Base Rates**

112. In 2014, the Commission granted a certificate of public convenience and necessity ("CPCN") for a 40 MW LM6000 gas peaking generation unit at the Pueblo Airport Generation Station ("PAGS").[76] In the Company's 2016 Phase I Rate Case, the Commission approved cost recovery for the LM6000 through the CACJA at a 6.02 percent WACC, which was lower than the Company's overall authorized WACC.[77] Property taxes and incremental O&M expense are recovered through base rates. The rider applies to Residential and Small General customers as an energy charge only and to larger customers as a demand charge.

113. In this Proceeding, the Company proposes to roll the investments, expenses, and revenues recovered through the CACJA Adjustment into base rates, eliminating the CACJA Adjustment. This amounts to $5.2 million being included in base rates, although the CACJA Adjustment revenue requirement is $6.4 million. The Company states that this will result in a $1.2 million annual savings for customers.

[76] Decision No. C14-0007 issued in consolidated Proceeding No. 13A-0445E on January 6, 2014.
[77] Decision No. C16-1140 issued in Proceeding No. 16AL-0326E on December 19, 20216.

114. Staff objects to moving the CACJA into base rates and supports maintaining LM6000 recovery in the CACJA rider, with the capital structure authorized in Decision No. C16-1140[78] and using the ROE authorized in this Proceeding. Staff asserts that allowing the LM6000 investments to be included in base rates would result in the Company realizing a profit of more than $600,000 on 2023 base rates.[79]

115. UCA also objects to moving the LM6000 recovery into base rates, urging the Commission to maintain capital structure previously authorized, noting that the Company has collected the return on this asset for some seven years without Commission review of the asset's valuation.[80]

116. UCA argues that the LM6000 should have been reevaluated to reflect its depreciating value, resulting in lower cost recovery and savings to ratepayers. UCA asserts that because the Company waited seven years to file another rate case, it continues to collect recovery based on inaccurate net plant valuation, resulting in $51.5 million collected from ratepayers. However, calculating the revenue requirement based on the 2023 net plant value, UCA determines that maintaining the CACJA for the LM6000 with the capital structure established in Proceeding No. 16AL-0326E, the revenue requirement would be decreased by $685,818.[81]

117. In its SOP, Pueblo agrees with Staff and recommends no change in the recovery mechanism for the LM6000.[82]

118. BHCOE rejects the arguments that LM6000 recovery should continue to be through the CACJA, specifically rejecting the unique capital structure applied to the asset in the

[78] *Id.* at ¶ 102.
[79] Staff SOP at p. 34.
[80] UCA SOP at p. 31.
[81] *Id*.
[82] Pueblo SOP at p. 26.

2016 Phase I Rate Case. BHCOE states that the LM6000 is financed in the same manner as all of the Company's assets, thus it should be subject to the same return as all investments. The Company contends that the unique capital structure assigned to the LM6000 was the result of the Commission's authorization of a 2015 HTY while acknowledging that the LM6000 would be operational beginning at the end of 2016. The Company cites the Commission's statement in Decision No. C16-1140 that the special treatment of the LM6000 financing costs was to be for the "first few years" of the generating unit's operation.[83]

**(2) Excess Tax Collection Associated with the LM6000**

119. Staff states the Company did not adjust the tax rate for the LM6000 in 2018 in accordance with the Tax Cuts and Jobs Act ("TCJA"), thus was collecting taxes at the 35 percent corporate tax rate instead of the 21 percent authorized by the TCJA. Staff calculates this overcollection at $3.7 million and argues this amount should be returned to ratepayers, amortized over three years.

120. Pueblo echoes Staff's concerns about the taxes collected for the LM6000, contending that BHCOE is obligated to follow the purpose of 2017's TCJA proceeding and comply with the requirement that the Company reimburse ratepayers for any tax collections above the authorized rate.[84]

[83] BHCOE SOP at pp. 27-28.
[84] Pueblo SOP at p. 31.

121. BHCOE rejects Staff's arguments of over-recovery citing the Commission's decision on the CACJA Adjustment, which BHCOE contends did not create a mechanism for true-up:

> The annual revenue requirement to be collected by the CACJA Adjustment rider shall not change unless modified by the Commission in a future Phase I rate case proceeding. However, the class cost allocators used to establish the rate values shall be modified as necessary based on the results of the Company's next Phase II rate case.
>
> Because the CACJA Adjustment rider will no longer serve as a special regulatory practice under § 40-3.2-207(3), C.R.S., the mechanism will not be used to "true-up" costs with revenues after December 31, 2016. The final true up will be in the six months beginning July 1, 2017, consistent with the terms of the existing CACJA Adjustment rider tariff sheets.[85]

122. BHCOE characterizes Staff's recommendation for reimbursement of taxes collected above the federal tax rate as single-issue rate making and a collateral attack on the Commission's TCJA decision. Furthermore, the Company contends that the Commission could not have re-set LM6000's revenue requirement on the tax rate alone, but would have had to also review all components, including the authorized WACC. BHCOE further argues that Staff's attempt to recover costs is retroactive ratemaking

123. Although there is no requirement that the LM6000 cost recovery be rolled into base rates, we find that doing so is appropriate because the capital structure initially applied to the LM6000 is obsolete and that consistent treatment is fair to the Company because the LM6000 is financed in the same manner as any of the Company's assets. However, we also find it is necessary to address the cost to ratepayers resulting from the Company's collection of taxes associated with the LM6000 at the 35 percent corporate tax rate rather than the 21 percent tax rate established by the TCJA. We note that the law established the corporate tax rate at 21 percent and the Company

[85] Decision No. C16-1140 at ¶¶ 104-105 issued in Proceeding No. 16AL-0326E on December 19, 2016.

should have applied that rate—consistent with ratemaking principles that actual costs should be used when available. Further, addressing the tax rate for the LM6000 asset is consistent with the Commission' stated intentions for the TCJA-related tax cuts: "The primary purpose of this proceeding is to ensure that Colorado utility customers benefit from the reduction in the federal corporate income taxes through lower rates."[86] Black Hills agreed that it was "committed to providing the benefits of the federal tax reductions to its customers."[87]

124. Keeping in mind these concerns for balance and fairness to the Company and to ratepayers, we authorize BHCOE to roll $5.2 million in cost recovery of the LM6000 into base rates, less the $3.7 million calculated as overcollection of taxes, amortized over three years.

**b. Rate Case Expenses**

**(1) Rate Expenses for This Proceeding**

125. BHCOE initially requested $450,000 for recovery of expenses for litigating this rate case but modified that amount to $266,459 in its Rebuttal Testimony; the Company also agreed to a four-year amortization for rate case expense recovery. The Company explained that since the depreciation study was not challenged by the intervenors, the cost for that consultant could be reduced, and also that it is using internal legal services as much as possible to reduce costs. Additionally, the Company removed travel expenses associated with the development and review of testimony, although the Company maintains those expenses are necessary.[88]

126. In its SOP, Black Hills states that it expects legal expense to be lower than $100,000 so the final expenses for this case would be less than $266,000. BHCOE asks the Commission to "look at total rate case expense and recognize that the overall expense is much less than customary,

[86] Decision No. C18-0075 at ¶ 9 issued in Proceeding No.18M-0047EG on February 1, 2018.
[87] *See* Black Hills TCJA Plan, filed on February 21, 2018, in Proceeding No. 18M-0074EG.
[88] Hr. Ex. 116, Harrington Rebuttal, pp. 75:20 – 76:2.

and award full recovery."[89] Black Hills further states: "If the Commission seeks to incent utilities to follow SB 23-191, it should not arbitrarily cut consultant expenses when overall expenses are already greatly reduced."[90]

127. Staff presents a relatively complex response to the Company's request to recover the expenses associated with this rate case. If the Commission is to grant a rate case expense for this specific case, Staff suggests eliminating recovery of most of the costs outside legal counsel and the ROE consultant, as well as reducing "Other Rate Case Expenses."

128. In its SOP, Staff does not provide a recommended rate case expense amount but recommends disallowance of "any cost that cannot be supported by a payment receipt." Staff further recommends disallowance of (1) travel costs, presumably from Pueblo to Denver or from elsewhere to Denver instead of to Pueblo, and (2) expenses related to food and alcohol. Staff recommends that "prior to Commission approval of rate case expense cost recovery, timely production of actual receipts for Staff review should be required."[91]

129. UCA estimates the total rate case expenses for this case should be $107,000, based on disallowance of costs associated with the Company's ROE consultant and travel expenses associated with the remote evidentiary hearing. With regard to legal counsel, UCA seeks to examine whether the final invoices of the Company's sole outside attorney are just and reasonable once final invoices are presented; UCA suggests a 50/50 split with ratepayers and shareholders for these costs, referencing SB 23-291 which it asserts shows the legislature intended for SB 23-291 to limit rate case expenses, and specifically those for outside attorneys and consultants. UCA recommends full allowance of the actual expenses of about $71,000 for the costs incurred

[89] BHCOE SOP at p. 32.
[90] *Id*.
[91] Staff SOP at p. 39.

for the Company's outside depreciation witness. However, UCA cautions that its recommendation is subject to revision after the final actual amounts are revealed at a technical conference.[92]

130. BHCOE rejects UCA's proposal to split rate case expenses between ratepayers and shareholders, noting that the Company is allowed to recover its actual rate case in accordance with prior Commission decisions and Colorado case law.[93] In its SOP, Black Hills notes that UCA's witness Skluzak admits that in the more than twenty rate cases he has been involved in, "without exclusion, a ROE consultant has been used, by the utility, in a Phase I revenue requirement."[94] The Company also argues that UCA presents no evidence that experts of the necessary caliber to support Black Hills' requests regarding its authorized ROE would accept in-house positions at a salary that would result in any savings.

**(2) Litigation Expense Tracker**

131. BHCOE seeks an expense tracker in the form of a regulatory account to account for litigation expenses they  incurred between rate cases. Black Hills explains that a rate case expense tracker would account for dollars above or below the amount approved in base rates and would account for it in either a regulatory asset or regulatory liability. The dollars would then be returned to or collected from customers at the next rate case. This would also avoid customer confusion and the addition of a new line item on customer bills. Black Hills portrays this proposed tracker as the alternative to implementing a negative general rate schedule adjustment ("GRSA"), or "a new line item on customer bills as a negative rate."[95]

132. UCA recommends that after the amortization of allowed rate case expenses is complete, the Commission should require Black Hills to file a "negative GRSA" to terminate such

[92] UCA SOP at pp. 36-38.
[93] Hr. Ex. 116, Harrington Rebuttal, p. 77:4.
[94] BHCOE SOP at p. 32.
[95] *Id.* at pp. 46-47.

cost recovery.[96] In its SOP, UCA argues that the negative GRSA is consistent with the intent of SB 23-291 to limit the amount of rate case expenses recovered from ratepayers and that a negative GRSA is needed to prevent "over-recovery" such as occurred from the Company's 2016 Phase I Rate Case.[97]

133. UCA opposes the approval of a litigation expense tracker. UCA argues that such a tracker would offer only a delayed benefit to customers once amortizations are complete and that allowing a WACC return on the deferred balance is inconsistent with intent of SB 23-291.[98]

**(3) Alleged Over Recovery of Rate Case Expenses**

134. Staff contends that Black Hills has significantly over recovered rate case expenses since its last base rate proceeding due to the passage of time. According to Staff, in the Company's 2016 Phase I Rate Case, the Commission authorized recovery of $550,000 corresponding to an annual amortization expense of $183,000. At that rate of cost recovery, Staff calculates the Company would have fully recovered those expenses by January 1, 2020, but since the last rate case, the Company has recovered some $962,000 in rate case expenses.[99] Therefore, Staff suggests that the Commission implement a negative rate case expense of $841,968, amortized over two years, taking into account the expenses for this Proceeding and the over-recovery of expenses from the 2016 Phase I Rate Case.

135. In Rebuttal Testimony, Black Hills characterizes Staff's recommendation as retroactive ratemaking and challenges Staff's proposition for a negative expense.[100] In its closing SOP, Black Hills argues that Staff witness Sigalla admitted that "the Commission did not explicitly

[96] Hr. Ex. 302, Skluzak Answer, p. 69:2 – 69:6.
[97] UCA SOP at p. 42.
[98] UCA SOP at pp. 42-43.
[99] Hr. Ex. 500HC, Sigalla Answer, p. 194:1 – 194:19.
[100] Hr. Ex. 116, Harrington Rebuttal, p. 79:1 – 79:14.

set a tracker" for rate case expenses in the previous rate case and further argues that Staff's position relies on a misapplied reference to the inputs to the cost of service model used to establish rates in that previous proceeding. According to Black Hills, the Commission makes no mention of what happens to this "cost of service input" if the Company does not file a rate case within the three-year amortization period. Black Hills also points out, citing Ms. Sigalla's Answer Testimony, that she acknowledges that the Commission had the opportunity to address this question in the previous rate case but "declined to adopt a process that could adjust the GRSA going forward for the purpose of reconciling actual incurred rate case expenses."[101] Black Hills concludes that Decision No. C16-1140 "cannot possibly serve as formal notice that a tracker has been established." Accordingly, Black Hills presents Staff's proposal for the Commission to adopt a negative rate case expense as an example of prohibited retroactive ratemaking.

**(4) Recovery of Other Litigation Expenses**

136. In its Direct Testimony, BHCOE initially sought to recover approximately $2.5 million of litigation expenses incurred in cases since the previous electric base rate proceeding; the Company proposed to amortize these costs over 24 months.[102]

[101] BHCOE SOP at p. 42.
[102] Hr. Ex. 103, Johnson Direct, Attach. SKJ-1, Schedule H-11.

| | |
|---|---|
| Renewable Advantage<br>(Proceeding No. 19A-0660E, Decision No. R20-0647) | $143,273 |
| 2022 ERP/CEP<br>(Proceeding No. 22A-0230E, Decision No. C23-0193) | $1,922,636 |
| 2017 Phase II Rate Design<br>(Proceeding No. 17AL-0477E, Decision No. C18-0162-I) | $283,315 |
| 2023 Distribution System Plan (DSP)<br>(Proceeding No. 23A-0357E) | $196,050 |
| **Total** | **$2,545,274** |

137. BHCOE modified its request in its SOP, withdrawing its request to include the $143,273 incurred in Proceeding No. 19A-0660E, stating that recovery there was "contingent on a resource going into service"[103]

138. BHCOE contends that the Commission previously approved regulatory assets in each of these cases for the Company to be able to seek recovery of these costs in its next rate case. The Company explains that the consultants that were hired in those cases bring expertise for which the Company lacks in-house capacity, specifically pointing to the 2022 ERP/CEP case, where "the Company needed to hire an independent evaluator, energy analysts, forecasting and modeling consultants, accounting experts, and legal counsel to navigate through the Phase I and Phase II portions of that proceeding, which only recently came to a final decision."[104] The Company further states that, through Rebuttal Testimony, it introduced evidence of receipts for all recovery sought and removed any recovery request for additional amounts that were not supported by invoices. And, in Rebuttal Testimony, the Company noted that detailed lists of charges associated with those previous proceedings were provided in the original filing workpapers, and UCA was pointed back to those workpapers in data request responses.[105]

[103] BHCOE SOP at p. 33.
[104] BHCOE SOP at p. 34.
[105] Hr. Ex. 118, Johnson Rebuttal, pp. 44:18 – 45:1.

139. Staff objects to Black Hills' proposal, arguing that Commission has not authorized recovery of expenses in the other proceedings, so the request to recover those amounts here should be denied.[106]

140. UCA also contests the proposed recovery of expenses associated with previous proceedings in its Answer Testimony, arguing that the Company does not explain how the total expenses were arrived at for each proceeding and therefore fails to provide evidence that the costs are just and reasonable.[107] In its closing SOP, however, UCA calculates the total costs of the previous cases as supported by invoices and other documentation to be approximately $2 million and recommends that the Commission split these costs evenly between ratepayers and the Company and its shareholders, with the COSS including approximately $255,862, which reflects a proposed amortization of four years, which UCA supports over a two-year amortization. [108] UCA states that upon its review of this $2 million of spending, "the overwhelming, or vast, majority of these expenses are for consultants and outside attorneys," citing the hearing transcript.[109]

141. In support of the 50/50 split, UCA contends that provisions in SB 23-291 support limiting rate case expense for outside consulting and legal services. UCA argues that SB 23-291 applies to these prior cases because the statutory language focuses on the cost recovery of such expenses from ratepayers and the "temporal focus is on when cost recovery is requested and not when the underlying costs are incurred."[110] UCA states the rationale for the proposed split is set forth in UCA's comments in the SB 23-291 rate case rulemaking in Proceeding No. 24R-0168EG.

[106] Hr. Ex. 500HC, Sigalla Answer, p. 196:11 – 196:16; Staff SOP at pp. 41-42.
[107] Hr. Ex. 302, Skluzak Answer, p. 72:13 – 72:18.
[108] *Id.* at p. 73:1 – 73:18.
[109] UCA SOP at p. 39.
[110] *Id.* at p. 41.

142. Reviewing the proceedings for which BHCOE is requesting recovery of litigation expenses, we find:

a. **Proceeding No. 17AL-0477E, 2017 Phase II Rate Design Proceeding**: The assigned ALJ granted Black Hills authority to create a regulatory asset "for the purpose of accumulating rate case expenses." Decision No. R18-0054 notes that: "Creation of the asset does not grant any presumption of prudence. Black Hills will have the burden to demonstrate prudence in a future proceeding seeking recovery." In its case, Black Hills estimated total expenses of $540,000, including: (1) legal notice - $80,000; (2) consulting fees related to the CCOSS model - $10,000; and (3) outside attorney fees - $450,000. Decision No. R18-0054 was adopted by the Commission, with modifications, upon consideration of exceptions, by Decision No. C18-0445. In its decision on exceptions, the Commission left undisturbed the authorization to create the regulatory asset for potential future recovery of the litigation expenses of this Phase II rate case granted by the ALJ.

b. **Proceeding No. 22A-0230E, 2022 ERP/CEP:** Through Decision No. C23-0193, the Commission approved a unanimous, comprehensive settlement agreement that included the provision that:

> Settling Parties agree that the Commission should authorize Black Hills to track and defer fees and costs associated with preparing and litigating this Proceeding, to be offset by any bid fees received as part of the Phase II solicitation process. The Settling Parties agree that legal fees shall be allocated 80/20 between ERP/CEP and RES support, respectively. All ERP/CEP costs and fees incurred related to this Proceeding shall be tracked through a non-interest bearing regulatory asset and presented for recovery through the Company's next-filed electric rate case. The Company may recover its RES legal fees and costs through the RESA.[111]

The Commission also granted BHCOE's application, which includes a request to "to track and defer costs associated with preparing and litigating this Proceeding, to be offset by any bid fees received as part of the Phase II solicitation process, for future recovery" through the proposed Clean Energy Plan Rider.

c. **Proceeding No. 23A-0357E, 2023 DSP:** Decision No. R24-0118 approved a Settlement Agreement joined by UCA and Staff that includes the provision: "The Parties agree that the Commission should approve the Company's proposal to create a regulatory asset to recover costs for the development of this 2023 DSP."

[111] Decision No. C23-0193 at ¶ 31 issued in Proceeding No. 22A-0230E on March 22, 2023.

> The settlement also includes details about certain costs that the parties agree to be included in the regulatory asset account for future consideration. For instance, in accordance with the DSP rules, Black Hills agreed provide draft proposed document(s) and model contract(s) for its Non-Wires Alternative (NWA) solicitation for a report that due on July 1, 2024. Black Hills also agreed to further evaluate hosting capacity analysis, a web portal, and a cost-benefit methodology. For all of these items, the agreement states: "The Company will be allowed to include costs associated with the development of these proposed document(s) and contract(s) in the regulatory asset account for this 2023 DSP."

143. In considering these litigation expenses for the current Proceeding and those that have occurred in recent years, we emphasize that the Company should only be authorized to collect the actual authorized expenses for any given proceeding. Limiting recovery to only actually incurred expenses is consistent with past Commission practice and the district court case in the prior BHCOE Phase I Rate Case.[112] In order to ensure that the Company does not continue to collect litigation expenses after recovery of what has been authorized, we direct the Company to implement a negative GRSA after the authorized litigation expenses have been recovered in this Proceeding. We reject the proposal of a rate case expense tracker.

144. We find that BHCOE has provided sufficient evidence to support its request for litigation expenses for this Proceeding and authorize the Company to recover no more than $184,000 for expenses related to litigating this Proceeding. We also agree with the Company that the Commission authorized litigation expense recovery for the previous proceedings as the Company has proposed, and confirm that BHCOE may recover $2.4 million associated with litigation expenses for Proceeding Nos. 17AL-0477E, 22A-0230E, and 23A-0357E. However, we agree with Staff that the Commission intended for the Company to collect only actual rate case

[112] *See* Order issued on April 30, 2018, in Denver District Court case number 17CV32445.

expenses for Proceeding No. 16AL-0326E and find that the Company collected $962,000 more than was authorized in Proceeding No. 16AL-0326E.[113]

145. We find that taking these expenses together for a net value for recovery is the most efficient and equitable way to address the issue and therefore authorize BHCOE to recover $184,000 for litigation expenses in this case and $2.0 million for litigation expenses for Proceeding Nos. 17AL-0477E, 22A-0230E, and 23A-0357E, offset by the $962,000 overcollection of funds for the litigation expense category since Proceeding No. 16AL-0326E. The net authorized recovery for these expenses is $1,268,400.

146. Several recommendations were made by the parties for amortization periods for cost recovery, ranging from BHCOE's request of four years for recovery of litigation costs for this Proceeding, a two-year amortization period for recovery of previous proceeding litigation expenses, and Staff's proposed two-year amortization for overcollection of litigation expenses in Proceeding No. 16AL-0326E. After considering these options, we authorize a three-year amortization period for the recovery of the expenses authorized above with no return.

#### c. Transmission Wheeling Revenues

147. In the Company's COSS, revenues collected from wholesale customers are credited against the calculation of the base rate revenue requirement for retail customers. Certain wholesale revenues relate to transmission wheeling provided to other utilities or other users of BHCOE's transmission system.

148. BHCOE's 2023 Rebuttal test year includes $6.7 million in FERC Account 456.1 "Revenue from Transmission of Elec by Others." Staff notes that in in Direct Testimony, Black Hills witness Ahrens recommends a known and measurable adjustment to this revenue credit

[113] Hr. Ex. 500HC, Sigalla Answer, p. 194:1-19.

due to the expiration of a Transmission Wheeling contract with Tri-State Generation and Transmission ("Tri-State") that accounts for $4.9 million of the transmission revenue.

149. Staff argues in that transmission wheeling revenues are volatile, and as demonstrated by the termination of the Company's contract with Tri-State, they are not within the Company's control. Staff argues that these features lend themselves toward "rider recovery, similar to fuel costs or the revenues from off system sales, both of which are recovered through the Energy Cost Adjustment."[114] Staff suggests that a general rate case such as this Proceeding is the correct venue to determine whether "such significant, volatile costs beyond the control of the utility would more appropriately be accounted within a rider mechanism." Staff thus recommends that revenues associated with transmission wheeling, FERC account 456.1, be accounted for in either the Company's quarterly ECA or the annual TCA.

150. In Rebuttal Testimony, the Company posits that if the Commission wants to recognize wholesale transmission revenues in the TCA, then the TCA should be modified to include all transmission related costs such as capital, O&M costs, and wheeling revenues, to better comport with the matching principle.[115] The Company further notes that its ECA is designed to recover fuel and purchased power costs.

151. We find that while Staff shows that transmission wheeling revenues are volatile and beyond Black Hills' control, its analysis is incomplete with respect to the associated costs those revenues are intended to offset. The practice of crediting transmission wheeling revenues to a retail COSS reflects a long-standing practice. Ongoing transmission-related O&M costs and rolled-in transmission capital investment costs are accounted for in Black Hills' base rates. Staff

[114] Staff SOP at p. 42.
[115] Hr. Ex. 125, Ahrens Rebuttal, p. 23:12 – 23:18.

provides no guidance for how to handle those costs vis-à-vis wholesale customers upon the implementation of its proposal for the Commission to require Black Hills to modify its ECA or TCA tariff to include credits for transmission wheeling revenues in those respective revenue requirements. Continuing the practice of crediting transmission wheeling revenues in the retail COSS for base rates is preferable to moving costs out of base rates into either the ECA or TCA in order to properly and fully implement Staff's proposal.

152. Therefore, we authorize BHCOE to apply revenues collected during the test year from transmission wheeling services against base rate costs in the determination of the final revenue requirement. We further approve the Company's *pro forma* adjustment to the test year amount of transmission wheeling revenues to account for the known and measurable impact of Tri-State no longer taking the associated service.

**d. Fleet Expenses**

153. In its Direct Testimony, BHCOE states that it has invested $13.80 million in vehicles from 2016 to 2023, including bucket trucks, medium duty pick-up trucks, diesel extended cab trucks, backhoe loaders, digger derricks, boring machines, and anti-idle systems to support emissions reductions.[116]

154. UCA recommends disallowing $654,444 of fleet investment in BHCOE's HTY. UCA observes that the fleet investment in 2021 through 2023 are higher than those in years prior to 2021. In its Answer Testimony, UCA shows the budgeted amounts provided in discovery, the actual amounts included in the cost of service, and calculates the lower of the two for each year since the Company's previous rate case.[117] UCA recommends limiting the fleet investment

[116] Hr. Ex. 102, Wolf Direct, p. 38:12 – 38:15.
[117] Hr. Ex. 301, England Answer (Rev 1), p. 23 Tbl. SEE-6.

included in the HTY to the average of those values calculated in its testimony, which would effectively result in a disallowance of $654,444 in the HTY.[118]

155. BHCOE responds that the increase in vehicle investment in the past few years is not due to an increase in vehicle count, but rather increased costs per vehicle due to inflation as well as environmental features to reduce emissions. The Company points out that the active vehicle count is actually lower in 2023 than the 2015-2023 average, and that it only replaces vehicles that meet specific age and mileage guidelines.[119]

156. BHCOE also clarifies that because it is no longer seeking recovery for 2024 capital investments, there are no budgeted costs for vehicles included in the Rebuttal cost of service study; rather, it is only seeking recovery of actual investments in vehicles.[120] The Company contends that these actual investments are used, useful, and necessary to ensure safe and reliable service to customers across the Company's service territory, even in inclement weather.[121]

157. We deny UCA's request to adjust fleet investment in this Proceeding. While costs have increased, we find nothing unusual about the fleet investment presented in this case—the number of vehicles has remained steady since the Company's previous rate case and BHCOE testified that it only replaces vehicles that meet age and mileage guidelines. BHCOE has provided sufficient evidence to support the purchase prices and environmental features that result in the increased investment compared to years past and that the investments are used and useful.

**e. Depreciation Expense**

158. UCA objects to the Company's use of year-end annualization of depreciation expense in its revenue requirement, arguing that since the Company is using a 13-month average

[118] *Id.* at p. 23:6 – 23:10.
[119] Hr. Ex. 117, Wolf Rebuttal, pp. 6:19 – 8:11.
[120] *Id.* at pp. 7:14 – 7:17.
[121] *Id.* at pp. 8:14 – 9:3.

rate base it should use a corresponding 13-month average depreciation expense calculation. UCA states that by using year-end plant balances the Company increases its revenue requirement by about $1 million.[122] UCA cites to the Commission's decision in the Proceeding No. 23AL-0348G in which the Commission disallowed Atmos' use of year-end plant for depreciation on a 13-month rate base as support for its position that a 13-month average depreciation expense calculation should be used.[123]

159. BHCOE counters that depreciation expense is included in the revenue requirement study for dollar-for-dollar recovery, but rate base is associated with the Company's authorized return. Therefore, consideration of rate base is relevant only calculating the return component of the revenue requirement and has no bearing on the actual depreciation expense the Company incurs. BHCOE cites several previous Commission decisions on this point, including Recommended Decision No. R18-0014, issued on January 8, 2018:

> The ALJ rejects the OCC's proposed reversal of the pro forma adjustment to depreciation expense. In determining revenue requirement, a pro forma adjustment to depreciation expense to reflect known and measurable changes is appropriate. A known and measurable adjustment to expense levels to reflect changes that have or will occur up to one year after the end of the HTY will not distort the relationship between investment, revenues, and expenses and will not violate the matching principle. Atmos witness Mr. Christian testified on rebuttal that over the course of the HTY, depreciation expense increased from the level experienced on average during the test year. There is no dispute about that fact. The *pro forma* adjustment to depreciation expense for known and measurable changes as of the end of the HTY will reflect depreciation expense when the rates adjudicated in this case are in effect, and it is reasonable.[124]

[122] UCA SOP at p. 30.

[123] Hr. Ex. 302, Skluzak Answer, p. 52:04 –52:14, citing Decision Nos. R23-0181 and C23-0293 in Proceeding No. 22AL-0348G.

[124] Hr. Ex. 118, Johnson Rebuttal, p. 38:08 – 38:27, citing Recommended Decision No. R18-0014 at ¶ 109 issued in Proceeding No. 17AL-0429G on January 8, 2018.

160. As to the Atmos rate case cited by UCA in support of its arguments, BHCOE contends that the Commission rejected Atmos' calculation of depreciation on year-end plant because Atmos failed to provide an explanation. BHCOE argues that here different circumstances apply because it has provided an explanation in Direct and Rebuttal Testimony and also notes this methodology has been upheld in other Commission decisions.[125]

161. We agree with UCA that matching the rate base valuation with the depreciation expense period is appropriate. As UCA points out, this approach is more consistent with the matching principle and the Company has not justified why deviating from these guidelines is appropriate here. Further, it is consistent with historical approach for BHCOE. Therefore, we direct the Company to use a 13-month average depreciation expense in its revenue requirement to correspond with the 13-month average rate base.

#### f. Production Meters

162. BHCOE includes $683,297 associated with 7,581 production meters in its COSS. The Company contends that in its previous Phase II case, Proceeding No. 17AL-0477E, the ALJ rejected the recovery of production meters from the Residential Net Metered customer class, but did not preclude the Company from recovering production meter costs in general.[126] The Company says that production meters are needed to identify actual behind the meter production, to accurately identify the number of renewable energy credits ("RECs") produced for compliance with the Renewable Energy Standard ("RES"), and that they also allow for the calculation of system peak net of renewable generation.[127]

[125] BHCOE SOP at p. 39, arguing that the Commission affirmed the use of depreciation expense balance at the end of the test period in two recent decisions: Decision No. R18-0014 issued in Proceeding No. 17AL-0429G on January 8, 2018, and Decision No. R23-0336 issued in Proceeding No. 22AL-0246G on May 30, 2023.

[126] Hr. Ex. 113, Ahrens Direct, p. 33:4 – 33:10.

[127] *Id*. at pp. 33:18 – 34:2.

163. Staff proposes a disallowance from rate base of $525,474 for production meters, associated with 5,830 net metering customers who have not opted for the Production Based Incentive option and instead are Net Metering Only.[128] Staff disagrees with the Company's claims that production meters are necessary to identify the number of RECs and calculate its system peak, saying that publicly available estimating tools, such as NREL's PVWatts, are available and provide reasonable estimates without the need for costs of installing and maintaining production meters.[129] Staff cites to 4 CCR 723-3-3664(e)(II), [130] which states that utilities "shall not require more than one meter per customer to comply with [net metering rules]," and 4 CCR 723-3-3658(f)(X), which says that, "for the standard rebate offer, the calculation of annual expected kWh of electricity will be based on the public domain solar calculator PVWatts Version 1 (or equivalent upgrade)." Staff also cites Decision No. C20-0289[131] in which the Commission rejected a request by Public Service to require production meters for small distributed generation customers, and instead directed Public Service to use PVWatts.[132]

164. BHCOE responds that these meters are used and useful, providing an analysis comparing estimated production to actual production for 2,516 PV systems below 10 kW in September 2024.[133] The analysis shows the difference between estimated and actual production for these systems totals approximately 82,000 kWh for this month. The Company states actual capabilities could be different than estimates due to the specific circumstances of solar panel installations, as well as the structures on which rooftop PV systems are installed.[134]

[128] Hr. Ex. 507, Dalton Answer, p. 19:3 – 19:5.
[129] *Id*. at 17:7 – 17:14.
[130] *Id*. at pp. 9:15 – 10:4.
[131] Decision No. C20-0289 at ¶ 46 issued in Proceeding No. 19A-0369E on April 28, 2020.
[132] Hr. Ex. 507, Dalton Answer, p. 21:1 – 21:7.
[133] Hr. Ex. 125, Ahrens Rebuttal, Attach. DSA-11.
[134] Hr. Ex. 125, Ahrens Rebuttal, pp. 21:12 – 22:2.

165. We deny BHCOE's request to include $683,297 in its COSS for production meters. We agree with Staff that the Commission's Rules do not require more than one meter per customer and find that expected kWh can be estimated using publicly-available tools, consistent with the approach taken for other utilities.[135] While BHCOE provides a broad analysis comparing the accuracy of production meters to the estimating tools, the analysis does not demonstrably use best practice methods or tools for its calculation, nor does it demonstrate any concrete use of the production meters on the system, underscoring that the meters are not necessary to providing utility service. Despite claiming to have found significant variations in performance, the Company admitted in the hearing that they did not use this information to notify the customers with the variations, nor did they use this information in system decisions. Without a sufficient demonstration of the need for these meters which serve a duplicative purpose, we are particularly mindful of the need for restraint in capital spending to assure rates that take affordability into mind.

### g. Compensation Issues

#### (1) Annual Incentive Program ("AIP")

166. BHCOE states AIP is critical for providing competitive total compensation for its employees and is used to align non-executive employees' performance with overall company performance targets. The Company further explains AIP provides employees with positions lower than Director level the opportunity to earn an annual incentive award based on performance and the salary grade. For non-union employees, the AIP percentage cannot exceed 150 percent of target. Union employees on the other hand, receive a negotiated AIP target percentage. The Company argues that AIP enhances BHCOE's competitiveness in the job market.[136]

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[135] *See* Decision No. C20-0289 at ¶ 46 issued in Proceeding No. 19A-0369E on April 28, 2020.
[136] Hr. Ex. 101, Harrington Direct, p. 48:21 – 48:23.

167. In line with previous Commission decisions, the Company capped the annual incentive program cost at 15 percent of annual base salary on an employee-by-employee basis.[137] The revenue requirement for AIP proposed is $1.3 million.[138]

168. Staff recommends Commission approval of the AIP cap of 15 percent on an employee-by-employee basis and further requests an adjustment of $50,000 in AIP expenses in the revenue requirement as a placeholder for limiting recovery to no more than 15 percent of base pay.[139]

169. BHCOE urges the Commission to reject Staff's proposal to adjust AIP by $50,000. The Company argues that the AIP value in the 13-month average HTY includes the 15 percent cap and clarifies that all AIP adjustments made in the HTY carried forward to the CTY by default. The Company further explains that the direct payroll annualization fell into the category of known and measurable adjustments and was included as an adjustment in the HTY that removes of the amounts of AIP over 15 percent.[140] Black Hills therefore contends another adjustment, as proposed by Staff would actually reduce AIP expenses below the intended cap of 15 percent.

170. We authorize recovery of AIP expenses at a 15 percent cap on an employee-by-employee basis as proposed by BHCOE. We deny Staff's requested adjustment of $50,000 because BHCOE has adequately explained how the appropriate adjustment was made in the HTY.

#### (2) Short Term Incentive Program ("STIP")

171. Company states STIP is a percentage of annual base salary applicable to employees in positions of Director and above. It is calculated in part by salary grade and market rates. As of

[137] *Id*.
[138] Hr. Tr. December 3, 2024, p. 267:11 – 267:17.
[139] Staff SOP at p. 37.
[140] Hr. Ex. 118, Johnson Rebuttal, 52:12 – 52:21.

December 31, 2023, BHCOE had two STIP-qualifying employees. The Company also receives an allocated portion of costs for STIP payout to qualifying BHSC employees.[141]

172. Consistent with recent Commission decisions, the Company is requesting approval to recover STIP expense for both direct BHCOE employees and BHSC employees, subject to a 15 percent cap on a per employee basis.[142]

173. UCA recommends that the Commission authorize BHCOE's request to cap STIP compensation expenses at 15 percent on a per employee basis.[143]

174. Staff agrees with the Company's proposal and recommends Commission approval. However, Staff argues that the Company failed to make the appropriate adjustments to HTY and CTY. Staff states the STIP total of $273,043 in the CTY is the correct figure, not the $325,553 shown in the HTY.[144]

175. Company witness Johnson contends the Company made the appropriate adjustments in both CTY and HTY to cap STIP expense at 15 percent on an employee-by-employee basis. The Company therefore requests the Commission reject Staff's recommendation as that would result in double counting the STIP expense beyond the proposed 15 percent cap.[145]

176. We authorize recovery of STIP expenses at a 15 percent cap on an employee-by-employee basis as proposed by BHCOE. We deny Staff's requested adjustment because BHCOE has adequately explained how the appropriate adjustment was made in the HTY.

[141] Hr. Ex. 101, Harrington Direct, p. 48:2 – 48:8.
[142] *Id*. at p. 48:19 – 48:23.
[143] Hr. Ex. 303, Fernandez Answer, p. 84:15 – 84:18.
[144] Hr. Ex. 500, Sigalla Answer, p. 168:12 – 168:14.
[145] Hr. Ex. 118, Johnson Rebuttal, 52:12 – 52:21.

### (3) Long Term Incentive Program ("LTIP")

177. BHCOE states that it offers LTIP in the form of restricted stock and performance share awards to vice president level and above employees. BHCOE states the program is intended to motivate employees to make significant contributions to the success of the Company and provide competitive compensation to attract and retain talent. The Company maintains that employees who receive restricted stock awards are incentivized to stay because the stock typically vests over three years.[146]

178. While BHCOE maintains that the full unadjusted equity compensation costs are prudent and necessary as part of the overall compensation package, the Company removed 50 percent of both direct and allocated equity compensation expenses in this Proceeding. The Company argues this is in alignment with prior Commission decisions.[147]

179. UCA supports BHCOE's proposal to remove 50 percent of LTIP equity compensation from the revenue requirement.

180. Staff recommends denying all LTIP expenses, consistent with previous Commission decisions, particularly Decision No. C16-1140 in the Company's 2016 Phase I Rate Case in which the Commission concluded that recovery of these costs was not reasonable and authorized the elimination of all expenses associated with LTIP. Staff notes that denying LTIP expenses results in a $424,000 reduction in revenue requirement.[148]

181. In Rebuttal, the Company maintains LTIP is key to attracting and retaining employees in a competitive market and asserts that it is Commission practice to remove 50 percent of LTIP, not 100 percent. BHCOE also states it erroneously eliminated 100 percent of LTIP equity

[146] Hr. Ex. 101, Harrington Direct, p. 50:5 – 50:12.
[147] *Id.* at p. 50:5 – 50:12.
[148] Hr. Ex. 500, Sigalla Answer, p. 170:15 – 170:19.

compensation in its Direct Testimony COSS. Therefore, in Rebuttal, it has corrected this error to remove 50 percent.[149]

182. Consistent with previous Commission decisions, we deny recovery of LTIP expenses in this Proceeding. While the Company contends that LTIP allows it to attract and retain employees, we find, particularly in this Proceeding, those arguments of potential benefit to the utility are outweighed when considering affordability of rates for BHCOE's service territory—balancing consumer and customer interests in this instance supports denial of recovery of this discretionary expense. We find that the Company and its shareholders should bear these costs without further burdening ratepayers.

**(4) Vacant Positions**

183. Staff objects to the inclusion in the revenue requirement of costs associated with positions that are blank and recommends removing $1,524,104 from the cost of service for 15 vacant positions at the end of 2023. Staff notes that the Company had 41 open positions in 2022 and an average of 26 open position since 2015.[150]

184. UCA also objects to these costs and argues the Company has experienced, on average, 26 annual open positions since 2015 and that there are always rolling open positions. Therefore, any recovery of payroll expenses should account for that expectation on a going forward basis, regardless of the test year approved. UCA contends that since the Company does not incur any labor expenses while a position remains open, an adjustment for vacancies is necessary.[151]

[149] Hr. Ex. 116, Harrington Rebuttal, p. 53:18 – 53:19.
[150] Hr. Ex. 500, Sigalla Answer, p. 178:1 – 178:10.
[151] Amended UCA SOP at p. 33.

185. UCA estimates the average annualized payroll impact to the Company's operations and maintenance budget would be $2 million. UCA recommends recovery of 50 percent of this annual impact, resulting in a reduction of $1 million from the revenue requirement.[152]

186. BHCOE disagrees with Staff and UCA because both parties assume the open positions will remain unfilled for an entire year. BHCOE emphasizes that from historical trends, these positions have not remained open and there is no basis to assume they will remain open for the whole year. In its Rebuttal Testimony, BHCOE modifies its request and applies a vacancy lag calculation to these open positions. The calculation considers the number of days a position is vacant and determines the value of the wages that should be removed from the revenue requirement. Applying the vacancy lag calculation results in a reduction in revenue requirement of $183,102.[153]

187. While we appreciate the Company's attempt to accurately account for the days that a position is vacant by applying its proposed vacancy lag calculation, in reviewing the annual position vacancy summaries from 2015 to 2023 provided by the Company,[154] we find that BHCOE's 15 vacancies at the end of the 2023 test year is not representative of the average of 26 vacancies annually in years for which the record contains data. In order to determine a more accurate value for vacancies, we consider that the average of 26 vacancies is about 70 percent higher than the 15 vacancies at the end of the HTY. We therefore gross up the Company's $183,000 vacancy calculation by 70 percent and determine that the revenue requirement should be reduced by $315,000 for position vacancies to represent a more typical year as supported by the data.

[152] Hr. Ex. 301, England Answer, p. 33:5 – 33:17.

[153] Hr. Ex. 118, Johnson Rebuttal, 53:6 – 53:14.

[154] Hr. Ex. 301, England Answer, Attachment SEE-21 contains data regarding the number of open positions from 2015 through 2023.

#### (5) Severance Pay

188. Staff objects to BHCOE's inclusion of severance pay expenses, and recommends the Commission deny recovery of these costs because only Black Hills, not ratepayers, should be responsible for the payment of severance because management should be accountable for decisions related to hiring and firing. This Staff proposal results in a reduction in the HTY cost of service of $304,742.[155] Staff further argues the Company is making severance payments that are substantial, and in certain circumstances exceeding the final annual salary and that this has implications on other employee costs which the Company should be responsible for.[156]

189. The Company asserts that severance expenses are prudently incurred in the normal course of business and have been allowed in the cost of service in several cases. Accordingly, the Company argues on Rebuttal that inclusion of $304,742, based on a three-year average, for per book severance expense in the HTY is appropriate, but in its Rebuttal Testimony applies a five-year average, resulting in a severance expense of $89,899 in the revenue requirement.[157]

190. We agree with Staff and find that the Company should be responsible for severance pay because the Company has control over its decisions to hire and fire employees and should therefore bear the costs of those decisions. We therefore deny the inclusion severance pay in the cost of service.

#### (6) Pension and Medical Expense

191. The Company states it has one defined benefit pension plan, the Black Hills Corporation Retirement Plan ("Pension Plan"), which is based on years of service and average earnings during a specific period prior to retirement. The cut-off date for the Pension Plan was

[155] Hr. Ex. 500, Sigalla Answer, p. 180:10 – 180:15.
[156] Staff SOP at p. 38.
[157] Hr. Ex. 118, Johnson Rebuttal, 47:16 – 47:19.

January 1, 2010. The Company explains that although the pension plan is closed to new entrants, some active participants who were eligible before the cut-off date continue to accrue benefits which is an ongoing financial obligation. BHC is also required to oversee the plan and complete valuations to ensure funds will be available to meet future benefit payment obligations.[158] These pension valuation assumptions include rate of pay, retirement rates, withdrawal rates, and rate of inflation.[159]

192. The Company also has a retiree healthcare plan, the Black Hills Corporation Retiree Healthcare Plan ("Healthcare Plan"). Employees that retire before the age of 65 as well as a grandfathered group of retirees older than 65 years old receive their benefits through the BHC self-insured retiree healthcare plans, while the all other eligible retirees over 65 years old are covered through an individual market healthcare exchange.[160] Assumptions specific to retiree healthcare include, healthcare cost trends, retirement rates, mortality tables, and medical participation rates.[161]

193. BHCOE requests recovery of the *pro forma* 2024 accrual amounts recorded for net periodic pension expense and net periodic retiree healthcare expense. The Company also proposes the addition of the pension and retiree healthcare regulatory assets and liabilities in the rate base calculation, as well as the associated balance sheet tax impacts. The Company asserts, this approach is consistent with prior Commission decisions.

194. Accordingly, BHCOE requests the inclusion of $373,582 in pension-related costs and $352,293 in retiree healthcare-related costs in its revenue requirement.[162]

[158] Hr. Ex. 104, Stevens Direct, p. 24:9 – 24:23.
[159] *Id.* at p. 26:11 – 26:13.
[160] *Id.* at p. 25:6 – 25:12.
[161] *Id*. at p. 26:14 – 26:15.
[162] *Id*. at p. 27:11-27:19.

195. Staff disagrees with the inclusion of the 2024 pension and retiree medical expense in rate base, with the associated WACC return, suggesting that implementing a tracker mechanism with true-up will prevent over- or under-recovery. Staff contends this will help both the Company and ratepayers in projecting these types of costs and dealing with volatility year to year. Staff also expresses concerns about the actuarial study used to determine the expense as it appears there has been an over-recovery since the last rate case.[163] Staff notes that the Company agreed with this proposal in Proceeding No. 19AL-0075G.[164]

196. We authorize recovery of costs related to the 2024 pension and retiree medical expense in rate base and approve a tracking mechanism, with no associated return, to be used to true-up the expenses to prevent over- or under-recovery and help both the Company and ratepayers in dealing with volatility year to year. The baseline amount shall be $725,284, comprising $372,991 for pension expense and $352,293 for retiree medical expense.

**h. Trackers**

**(1) Property Tax Expense Tracker**

197. BHCOE requests Commission approval to introduce a deferred accounting tracker for property tax expense. The Company argues this is necessary to prevent under or over recovery because these costs are volatile, support local communities, are outside the control of management and obligations that must be paid. The Company notes the Commission has approved the property tax tracker in recent proceedings for both gas and electric utilities. Company proposes a baseline property tax amount of $11,364,503[165] and a carrying cost of accumulated balances at the Company's authorized WACC.[166]

[163] Hr. Ex. 500, Sigalla Answer, p. 140:3 – 140:7.
[164] *Id*. at p. 141:3 – 141:5.
[165] Hr. Ex. 103, Johnson Direct, p. 66:3 – 66:4.
[166] Hr. Ex. 101, Harrington Direct, p. 103:18 – 103:19.

198. Staff supports the creation of a regulatory asset for property tax expense because the property tax expense should be a pass-through from the local taxing authorities. Staff recommends there be no return associated with this regulatory asset.

199. UCA recommends the Commission reject the proposed tracker because the expenses do not meet the criteria for a regulatory asset that an expense be unexpected, non-routine, and extraordinary. Should the Commission authorize a regulatory asset, UCA recommends there be no associated return and that the Company's ROE be revised downward to reflect decreased risk of cost recovery.

200. We agree with Staff that because property tax expense is a pass-through, a tracker for property tax expense is appropriate. We therefore approve a Property Tax Expense tracker, with no associated return; the baseline amount for Property Tax expense is $10,680,772[167].

**(2) Insurance Expense Tracker**

201. The Company proposes the creation of a new regulatory asset to defer and track insurance expenses above the amount included in base rates. Black Hills argues since its last rate case in 2016, insurance rates have become more unpredictable, especially in the last year.

202. Staff and UCA oppose this proposed tracker, stating that the Company has not provided evidence that these expenses are not unexpected, non-routine, or extraordinary and do not require the extraordinary cost recovery of a tracker. Staff argues that insurance costs are related to perceived risk, which BHCOE management can affect by taking preventative measures, including maintenance and vegetation management, thereby reducing insurance premium costs.[168]

[167] This amount excludes Peak View Wind Facility as expenses associated with Peak View Wind Facility are recovered through the ECA and RESA.

[168] Hr. Ex. 500HC, Sigalla Answer, p. 211:11-17.

203. We deny the request for an Insurance Expense tracker. We agree with Staff and UCA that the Company has not demonstrated that insurance expenses are extraordinary or strictly pass through costs that need not be litigated in a rate case.

**(3) PUC Administrative Fees Tracker**

204. All regulated electric and gas utilities in Colorado are required to pay annual Commission administration fee. The deferral of Commission administration fees was permitted by SB 21-272. BHCOE proposes to establish a regulatory asset to defer and track Commission administration fees above the amount included in base rates. The proposed baseline PUC administration fee amount is $978,959. This is the base amount that will be used for tracking going forward.[169]

205. Staff supports the creation of a regulatory asset for PUC administrative fees to ensure that recovery is no more or less than the actual fee. Staff recommends there be no return associated with this regulatory asset.

206. UCA recommends the Commission deny this request because the PUC Administrative Fees are not unexpected, non-routine, and extraordinary in nature and therefore do not meet the criteria for a regulatory asset. Should the Commission authorize a regulatory asset, UCA recommends there be no associated return and that the Company's ROE be revised downward to reflect decreased risk of cost recovery.

207. In order to ensure that only actual PUC administrative fees are recovered, we authorize the Company to establish a tracker for PUC administrative fees, with no return. The baseline amount for PUC Administrative Fees is $974,172.

[169] Hr. Ex. 103, Johnson Direct, p. 68:9-68:11.

### (4) Green House Gas Fees Expense Tracker

208. The Colorado Environmental Justice Act (House Bill 21-1266) required the Air Quality Control Commission ("AQCC") to establish a fee for greenhouse gas emissions. In 2024, the AQCC adopted rules that created the GHG fees to fund the work of the Air Pollution Control Division (of the Colorado Department of Public Health and Environment) to address climate change. BHCOE requests authorization to defer and track fees for greenhouse gas emissions in a regulatory tracker. The proposed baseline amount is $43,493[170] and the Company proposes to include carrying cost at authorized WACC.[171]

209. Staff recommends denial of proposed regulatory asset treatment for Green House Gas fees, arguing there is no evidence to support the extraordinary treatment of this expense and suggesting the Company can recover this cost through a pro-forma adjustment to the test year. Staff believes allowing this regulatory asset could be misconstrued as a Commission order that might allow recovery of otherwise prohibited costs.[172]

210. UCA also recommends the Commission deny this request because the expenses are not unexpected, non-routine, and extraordinary in nature and therefore do not meet the criteria for a regulatory asset. Should the Commission authorize a regulatory asset, UCA recommends there be no associated return and that the Company's ROE be revised downward to reflect decreased risk of cost recovery.

211. We agree with Staff that the Green House Gas fees are not the type of expenses for which a tracker is appropriate for and do not require a tracker for future recovery.

[170] Hr. Ex. 103, Johnson Direct, p. 69:15.
[171] Hr. Ex. 101, Harrington Direct, p. 103:18 – 103:19.
[172] Hr. Ex. 500, Sigalla Answer, pp. 214:18 – 215:2.

**(5) Vegetation Management Expense Tracker**

212. BHCOE requests the Commission approve its proposal to defer and track vegetation management expenses above the baseline amount of $3,812,020 in the revenue requirement.[173] The Company states this cost is largely driven by increased third-party contract vendor costs tied to a contract expiration and renewal and an identified need for increased contract crew staffing levels.[174] The Company proposes a three-year deferral period starting when BHCOE notifies the Commission of the deployment of its technological solution. If the Company seeks to extend the tracking mechanism at the end of the three years, it may request additional Commission approval.[175]

213. Staff recommends the Commission deny this request, contending that vegetation management expenses are not different from other expenses in the cost of service and the Company can control these costs.

214. UCA also recommends the Commission deny this request because the expenses are not unexpected, non-routine, and extraordinary in nature and therefore do not meet the criteria for a regulatory asset. Should the Commission authorize a regulatory asset, UCA recommends there be no associated return and that the Company's ROE be revised downward to reflect decreased risk of cost recovery.

215. We deny BHCOE's request for a vegetation management expense tracker. We agree with Staff that these expenses are not unusual or extraordinary, are within the control of the Company, and do not require a tracker for future recovery.

[173] Hr. Ex. 103, Johnson Direct, p. 69:21 – 69:24.
[174] Hr. Ex. 108, Dunn Direct, pp. 13:15 – 14:6.
[175] *Id.* at p. 19:15 – 19:21.

#### (6) Customer Communication and Education Plan Expense Tracker

216. The Company proposes a Customer Communication and Education Plan to notify and educate customers about the changes resulting from proposed structural changes in this rate case like moving from inclining block rate ("IBR") to flat energy charge, class cost of service and optional time-of-use. The Company states it will achieve this by updating comprehensive information on the website, news release distribution to local media outlets, direct customer communication, distribution of information and presentations to local chambers of commerce, and presentations to economic development organizations and service clubs.

217. BHCOE states that it did not include this expense in its COSS because the plan will not begin until 2025. In order for the Company to have these costs considered for future recovery, BHCOE proposes to defer and track all expenses when it is implemented, after final Commission decision in this Proceeding.

218. Staff recommends denying this request, maintaining that allowing a tracker for these expenses could violate the requirements of SB 23-291. Staff believes allowing this regulatory asset could be misconstrued as a Commission order that might allow recovery of otherwise prohibited costs.[176]

219. UCA also recommends the Commission deny this request because the expenses are not unexpected, non-routine, and extraordinary in nature and therefore do not meet the criteria for a regulatory asset. Should the Commission authorize a regulatory asset, UCA recommends there be no associated return and that the Company's ROE be revised downward to reflect decreased risk of cost recovery.

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[176] Hr. Ex. 500, Sigalla Answer, pp. 214:18 – 215:2.

220. We deny the Customer Communication and Education Plan tracker. We acknowledge Staff's concerns related to the allowed costs under SB 23-291 and agree with UCA that the expenses are not unexpected, non-routine, and extraordinary and do not require a tracker for future recovery.

### i. Aquila Pension and Retiree Medical Expense

221. Staff asserts that when Black Hills acquired Aquila, Inc. ("Aquila") in 2008, Aquila had an underfunded pension and retiree medical plan. Staff contends that although the Commission never authorized amortization expenses or established a regulatory asset, Black Hills began collecting money from ratepayers for the underfunding; Staff states that for 17 years, the Company has annually collected some $573,000 from rate payers.[177] Staff raised the issue in the 2016 Phase I Rate Case and the Commission allowed amortization of the expense to remain in the cost of service based on BHCOE's representation that the pension expense had been included in prior rate cases. However, the Commission agreed with Staff that the record was not clear on the issue and directed BHCOE to include more detail in its direct case in its next Phase I rate case.[178]

222. Staff argues that the Company failed to follow this directive in this Proceeding because the Company only indicated in its direct case that the costs had been fully amortized prior to the HTY ending December 31, 2023 and did not provide any additional detail on questions surrounding the Aquila pension issue.[179] Staff further contends that while the asset could have been fully amortized in the 2016 Phase I Rate Case, it has not been removed from rates currently in effect. Staff recommends the Commission require BHCOE to reimburse ratepayers some $13.5

[177] Hr. Ex. 500C, Sigalla Answer (Rev. 1), pp. 145:18 – 146:2.
[178] *See* Decision No. C16-1140, at ¶ 137 issued in Proceeding No. 16AL-0326E on December 19, 2016.
[179] Hr. Ex. 500C, Sigalla Answer (Rev. 1), pp. 152:12 – 153:7.

million collected from ratepayers since the Aquila acquisition. Staff suggests returning these dollars to ratepayers over three years, this will reduce the cost of service by $4,511,853 annually.[180]

223. BHCOE responds that the Commission approved the recovery of the amortizations in the Decision No. C16-1140 in the 2016 Phase I Rate Case. The Company explains that it did not include detail as to the costs in this Proceeding because there is no amortization of Aquila-related costs in the revenue requirement for this Proceeding.[181] BHCOE contends that Staff's recommendation in this matter constitutes retroactive ratemaking and offers that the Company did provide detailed information about the Aquila and SourceGas pension and retiree medical regulatory assets in the 2017 Rocky Mountain Natural Gas rate case.[182]

224. We are very frustrated with and disappointed in BHCOE's lack of forthrightness on this issue in this Proceeding and in the 2016 Phase I Rate Case. Based on the record we have, the Company has not been forthright in how it has dealt with the Aquila pension and retiree medical expense and likely has engaged in delay tactics since the 2016 Phase I Rate Case so that it did not have to provide the Commission with relevant information before these expenses were paid in full by ratepayers.

225. We are further dismayed at the magnitude of the total amount paid by ratepayers over the years without any prior in-depth Commission analysis of the appropriateness of recovery, but do not find a path through which we can require these costs to be reimbursed to BHCOE's ratepayers.

226. We therefore reluctantly deny Staff's request to require reimbursement of $13.5 million to ratepayers. However, we note that such behavior by the Company does not

[180] Staff SOP at p. 17.
[181] Hr. Ex. 119, Stevens Rebuttal, pp. 31:13 – 32:13.
[182] BHCOE SOP at p. 45, citing Direct Testimony of Kimberly F. Nooney filed in Proceeding No. 17AL-0654G.

encourage an environment of trust or confidence among the Commission, parties and customers and the Company. While in this case we have not found a reasonable way to require reimbursement of these expenses, such actions may provide important context for future decisions surrounding the Company's decision making.

### 7. Class Cost of Service and Rate Design

#### a. Cost Allocation Methodology

227. BHCOE proposes to allocate production costs using the Average and Excess ("A&E") Four Coincident Peak ("4CP") method ("A&E 4CP") and transmission costs using the 4CP method, as was approved in BHCOE'S most recent Phase II rate case, Proceeding No. 17AL-0477E.[183]

228. Coincident Peak ("CP") refers to the hour or the month of the year when the maximum system load occurs. 4CP specifically refers to the average of the system peaks occurring in the four months of June through September (the summer months). A&E combines the base load demand of all customer classes (the "average" component) with the customer class demand attributable to peak load demand (the "excess" component). In the case of A&E 4CP specifically, the "excess" is determined based on the difference between the average of the customer classes' four summer month coincident peaks and the customer classes' average demand.

229. As part of this Proceeding, the Company performed a system load study, using the Average Seasonal Coincident Peak Method, which defines a seasonal coincident peak load month as any month whose system peak load is equal to or greater than 90 percent of the annual system peak load.[184] This study showed the Company's system peak consistently occurring in the summer

[183] Hr. Ex. 110, Hyatt Direct, p. 57:5 – 57:10.
[184] *Id.* at p. 46:3 – 46:7.

months, with only those months being equal to greater than 90 percent of the annual system peak load for the past ten years.[185]

230. The Company asserts that the A&E 4CP method is appropriate for allocating production costs because it both assigns a minimum level of cost responsibility to all customer classes while also basing that responsibility on the demand during summer months, which “reflects how production costs are driven by summer load.”[186]

231. BHCOE proposed to use the 4CP method to allocate transmission costs, rather than A&E 4CP. This method allocates costs to the customer classes based solely on their responsibility for demand during the summer months. The Company asserts that, unlike generation resources, there is no tradeoff between capital costs and energy costs when building transmission plant, and the same type of transmission line would be built to serve load regardless of how heavily it is loaded at different times; thus, it says, an average and excess type of allocation method would not be appropriate for transmission costs.[187]

232. Staff does not take issue with any of BHCOE’s CCOSS methodologies at this time; however, it does encourage BHCOE to consider alternative allocation methods for energy-only generating resources in the future. Staff notes that in Public Service’s last Phase II rate case, Proceeding No. 23AL-0243E, Public Service presented several innovative methods for energy resources, including Probability of Dispatch (“POD”) – Peak Hours (“PH,” collectively “POD-PH”), which was ultimately approved by the Commission. However, Staff also notes that the Peak View wind facility is still recovered through the ECA and RESA, and so it does not see such methodologies as necessary for BHCOE at this time.

[185] *Id.* at p. 47, figure DNH-12.
[186] Hr. Ex. 110, Hyatt Direct, pp. 59:21 – 60:3.
[187] *Id.* at pp. 61:9 – 62:4.

233. UCA disagrees with BHCOE's use of the A&E 4CP method to allocate production costs. UCA contends that the A&E 4CP method is inconsistent with the NARUC Manual, as well as accepted industry practices.[188] It characterizes the use of CP rather than non- coincident peak ("NCP") demands in the development of the A&E method as a "fundamental error" in BHCOE's approach.[189] Citing to the NARUC Electric Cost Allocation Manual, UCA claims that the use of CP rather than NCP demands when calculating the A&E method results in allocation that is identical to allocation under a CP method.[190]

234. Arguing that class cost of service studies are imprecise, UCA recommends the Company be directed to use the average of five methodologies:[191]

- A&E non-coincident peak, which determines the excess based on individual class peaks, rather than the average of the four system peaks in the summer months;
- 12CP, based on the average of the system peaks through the whole year rather than just those in the summer months;
- Peak and Average (P&A), which assigns costs partially on the basis of peak load and partially on the basis of kWh usage throughout the year;
- Base-Intermediate-Peak (BIP), which weighs different individual resources based on their role in the utility's generation portfolio; and
- Probability of Dispatch, which looks at the actual hours that plants are dispatched, and assigns costs associated with those plants to customer classes based on their loads at that time.

235. UCA also disagrees with BHCOE's use of 4CP to allocate transmission costs because a calculation based solely on peak hours of the year does not consider that transmission facilities are used virtually every hour of the year. UCA also notes that there are economies of

[188] Hr. Ex. 305, Watkins Answer, p. 6:14 – 6:18.
[189] Hr. Ex. 305, Watkins Answer, p. 22:15 – 22:17.
[190] *Id.* at p. 24:4 – 24:30.
[191] UCA's five methods of production cost allocation are described in Hr. Ex. 305, Watkins Answer, pp. 14-19; they are calculated in Hr. Ex. 305, Watkins Answer, pp. 29-38; class rates of return at present rates using the methods are provided in Hr. Ex. 305, Watkins Answer, p. 39 Tbl. 15.

scale associated with high voltage transmission lines, which it says would make a solely linear relationship between cost and peak load inaccurate.[192]

236. UCA describes two different philosophies regarding the allocation of transmission plant: One that transmission is essentially an extension of generation plant, and so transmission should be allocated consistently with generation costs; the other that transmission facilities have a known and measurable load capability, and so contributions to peak load should serve as the basis for transmission cost allocation.[193] UCA asserts that 12CP strikes a reasonable balance between these two philosophies, and also notes that 12CP is commonly used by both state regulatory commissions as well as FERC to allocate transmission costs.[194]

237. In Rebuttal Testimony, BHCOE agrees to adopt Staff's recommendation to revisit the appropriateness of all allocation methods in the CCOSS in its next rate case.[195] The Company maintains its position that A&E 4CP for production costs and 4CP for transmission costs are appropriate methodologies, in this Proceeding. The Company asserts that its CCOSS was developed following empirically sound industry standards.

238. BHCOE notes that the only difference between its A&E 4CP allocator and UCA's A&E NCP allocator is the "excess" component, which would result in a large shift of costs.[196] BHCOE also asserts that a 4CP allocator is more appropriate for transmission than a 12CP allocator because BHCOE's system peaks during the summer months, and that those customer classes that contribute more to those system peak months should be assigned a higher level of transmission plant.[197]

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[192] Hr. Ex. 305, Watkins Answer, p. 27:10 – 27:21.
[193] Hr. Ex. 305, Watkins Answer, pp. 26:19 – 27:9.
[194] *Id.* at pp. 27:22 – 28:2.
[195] Hr. Ex. 123, Hyatt Rebuttal, p. 13:16 – 13:18.
[196] *Id.* at p. 15:1 – 15:12 (quantified in figure DNH-2R).
[197] *Id.* at p. 15:14 – 15:20.

239. We find that the A&E 4CP methodology is appropriate for production costs in this Proceeding. A&E 4CP has been used by BHCOE and Public Service for a number of years and is appropriate with the Company's current production system, as the Peak View wind facility is currently being recovered through the ECA and RESA, and no Clean Energy Plan resources are included in rate base in this Proceeding. While we acknowledge the alternative methodologies proposed by UCA, we find no compelling evidence in the record to deviate what has been the Company's practice.

240. As the resource mix continues to change, we also find that a broader discussion of production cost allocation methodologies in BHCOE's next Phase II proceeding[198] would be instructive and direct the Company to provide an analysis of other cost allocation methodologies in its next Phase II rate case where it is likely that the Peak View wind facility and potentially other energy resources will be included in rate base. In its next Phase II rate case filing, we direct BHCOE to include an analysis of:

- A&E 4CP, as proposed by the Company and approved by the Commission in this proceeding
- Each of A&E NCP, 12CP, P&A, BIP, and POD, as proposed by UCA in this proceeding;
- POD-PH with 1,000 peak hours,[199] as approved by the Commission for PSCo in Proceeding No. 23AL-0243E; and
- POD-PH with 100 peak hours.

241. For each of the above methods, as well as any additional methods the Company wishes to discuss or propose, the Company shall calculate and provide allocation factors for each customer class associated with those methods. In addition, for each method, the Company shall

[198] Decision No. C16-1140 at ¶ 204 issued in Proceeding No. 16AL-0326E on December 19, 2016, we leave this requirement undisturbed in this Proceeding.

[199] BHCOE should also provide enough hourly data to calculate other potential peak hour modifiers.

either conduct a CCOSS showing rates of return for each customer class under that method or, if the Company chooses not to conduct a CCOSS under that method, explain why the Company believes the method would be inappropriate to use for production cost allocation. Finally, the Company shall provide a proposal as to which of the analyzed allocation methods or combination of methods it asserts should be used to set rates.

242. Similarly, we approve the 4CP method to allocate transmission costs, as proposed by BHCOE and approved in BHCOE's previous rate case. BHCOE has demonstrated that it is still a summer-peaking utility, and allocation of transmission costs based on those summer months aligns with cost causation. However, we also require a fuller discussion of transmission cost allocation methodologies in BHCOE's next Phase II proceeding. While the evolution of the transmission system is not as obviously paired with any single factor as production is with new resources such as wind and solar, it is certainly still evolving, as evidenced by myriad cases before the Commission currently and in recent years. Any potential change in transmission cost allocation methodology should be considered in conjunction with potential changes in production cost methodology to the extent feasible.

243. BHCOE should address the following methods in its next Phase II proceeding, though other methods may also be discussed or proposed:

- 4CP, as proposed by the Company in this Proceeding;
- 12-CP, as proposed by UCA in this Proceeding;
- POD-PH with 1,000 peak hours; and
- POD-PH with 100 peak hours.

244. For each of the above methods, as well as any additional methods the Company wishes to discuss or propose, the Company shall calculate allocation factors for each customer

class associated with those methods. In addition, for each method, the Company shall either conduct a Class Cost of Service Study showing rates of return for each customer class under that method or, if the Company chooses not to conduct a CCOSS under that method, explain why the Company believes the method would be inappropriate to use for transmission cost allocation. Finally, the Company shall provide its proposal as to which of the analyzed allocation methods or combination of methods it asserts should be used to set rates.

**b. Rate Mitigation**

245. In its initial filing, the Company proposed a rate mitigation strategy to minimize bill impact but would also set rates as close to the cost of service for each customer class as is practical while minimizing cross-subsidization between classes.[200] With its Rebuttal Testimony, BHCOE proposed a uniform 13.99 percent increase across all rate classes, consistent with its revised cost of service study. While this mitigation strategy reduces the 20.44 percent increase for the Residential rate class that would otherwise occur based on the Company's CCOSS, the Large Power Service rate class sees an increase from 0.66 percent under the CCOSS to 13.99 percent with the rate mitigation strategy.

246. Staff objects to a rate mitigation strategy because it asserts that if residential customers do not bear the full costs that they impose on the system, the price signals that encourage conservation and energy efficiency are lost. Conversely, with cost burden shifted to the commercial classes, businesses might over-invest in energy efficiency and distributed energy or could move to a new location with lower energy rates. Staff further notes that rate mitigation shifts attention away from the requested rate increase itself and recommends the Commission look to

[200] Hr. Ex. 110, Hyatt Direct, p. 21:6 – 21:9.

adjustments to the Company's cost of service in order to minimize the rate increase for all BHCOE's customers.[201]

247. Cañon City/Florence agrees with Staff that rather than implementing a mitigation strategy, the Commission should closely consider all proposed cost recovery and limit the overall amount of the rate increase. Cañon City/Florence also recommends the Commission consider phasing in capital costs into rate base, with customer rate increases occurring over time.[202]

248. We acknowledge Staff's arguments that the if customers are not required to bear the full cost of their energy load and have the opportunity to respond to price signals, conservation efforts might be compromised. However, it is clear that many residential customers in BHCOE's service territory are struggling with their current bills and any rate increase will likely cause efforts to minimize energy use. Additionally, we are cognizant of the fact that the rate mitigation could exacerbate the problems the communities in BHCOE service territory are having with attracting new business development and that residential rate mitigation comes at the expense of rates for existing or new businesses.

249. At the Technical Conference, BHCOE presented updated its CCOSS. This revised CCOSS indicated a uniform 9.48 percent increase would be consistent with the Commission's decision, but the CCOSS also resulted in a $3.3 million, or 29 percent, decrease for Large Power Service Transmission customers. Applying a 9.48 percent increase to all rate classes resulted in a revenue increase of $1.0 million for Large Power Service Transmission customers, with a Residential Class Total revenue increase of about $7.9 million and a Small General Service class revenue increase of about $2 million.

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[201] Staff SOP at p. 49.
[202] Cañon City/Florence SOP at pp. 19-21.

250. Considering the Commission’s discussions about the impact a rate mitigation strategy would have on commercial customers, BHCOE provided an alternative mitigation strategy that applies a 10.13 percent increase across all rate classes, while assigning no increase to the Large Power Service Transmission schedule. The result is a Residential Class Total revenue increase of about $8.4 million and Small General Service class revenue increase of about $2.1 million.

251. We reiterate our concerns that an answer to rate mitigation is elusive and modify our direction that the Company apply a uniform percentage increase across all rate classes to direct the Company to apply a zero percent increase for the Large Power Service Transmission class and a 10.13 percent increase uniformly across all other rate classes. While there are no perfect solutions, this modification should move toward an appropriate balance of lessening the rate impact of the Residential class and while minimizing rate increases that are borne by large commercial customers given that the cost causation does not indicate such an increase should be borne by the large commercial customers.[203]

252. However, we find that in this Proceeding, approving the proposed rate mitigation strategy to apply a uniform percentage increase across all rate classes, except the Large Power Service Transmission class, is appropriate and authorize the Company to modify its final rates accordingly.

#### c. Inclining Block Rates (“IBR”)

253. BHCOE proposes to eliminate its IBR structure for residential customers and replace it with a flat energy rate applied to all kWh.[204] The Company states that IBR are a barrier

[203] Chairman Eric Blank was not present at the March 5, 2025 CWM where this clarification was discussed.
[204] Hr. Ex. 101, Harrington Direct, p. 60:4 – 60:6.

to electrification, specifically the installation of heat pumps, and cites to cost causation, fairness, equity, and ease of understanding as reasons to eliminate IBR.

254. The Company compares meter data from customers participating in the BHCOE Energy Affordability Program to all residential customers and finds that customers participating in the program used more electricity than the average customer in all months in 2023.[205] Based on this analysis, the Company states that inclining block rates may result in income-qualified ("IQ") customers actually having higher rates than under a flat rate structure, and so eliminating inclining block rates would be a way to promote equity.[206]

255. Staff supports BHCOE's proposal to eliminate its inclining block rate structure, saying that inclining block rates are not cost-based and are inconsistent with policy objectives of beneficial electrification.[207]

256. EOC suggests that the shift between rate cases is due to the lack of price signals for Black Hills Energy Assistance Program ("BHEAP") customers.[208] While the Company asserts that the elimination of IBR is a matter of equity, EOC claims that the elimination would be a case of focusing on equality and inadvertently creating an inequitable result.[209] EOC also points out that the Company supported the inclining block structure in its 2017 rate case.[210]

257. In Rebuttal Testimony, BHCOE acknowledges that it has not done an analysis on non-BHEAP IQ customers to see if those customers use more or less energy than the class average, but the Company contends that since BHEAP customers do use more electricity than the average

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[205] Hr. Ex. 113, Ahrens Direct, p. 22:18 – 22:20.
[206] *Id.* at p. 24:12 – 24:15.
[207] Hr. Ex. 501, O'Neill Answer, p. 38:1 – 38:15.
[208] *Id.* at p. 27:1 – 27:4.
[209] Hr. Ex. 600, Bennett Answer, p. 27:7 – 27:11.
[210] *Id.* at p. 24:1 – 24:4.

residential customer, the same could be true of other IQ customers.[211] BHCOE questions whether IBR is appropriate for assisting IQ customers and notes that some high energy use customers will be IQ and would be penalized under the IBR structure.

258. We find that the current IBR rate structure is appropriate and direct the Company to maintain this structure. We deny the Company's request to implement a flat-rate structure.[212] We share EOC's concerns about the impact that replacing IBR could have on IQ customers and find compelling EOC's argument that BHEAP customers may have difference price signals than other IQ customers. We acknowledge that there is no universal answer, the IBR structure is an established rate structure that gives customers—particularly low-income customers—an opportunity to save on their bills through conservation. We find this is consistent with our concerns about affordability in this Proceeding. The commission would welcome further research into the energy use of BHEAP customers and the IQ population at large for inclusion in the next rate case.

**d. Time of Use ("TOU") Rates**

259. BHCOE proposes TOU rates for all customer classes on an opt-in basis.[213] The Company currently has number of TOU rate schedules that it proposes to simplify into a consistent structure for all classes. The Company states that it believes this consistency will reduce customer confusion and lead to greater acceptance of TOU rates.[214]

**(1) Price Ratio**

260. BHCOE proposes a 2:1 price ratio for all TOU rates. Its current TOU rates include varying price ratios, from 1.2:1 for Large General Service Secondary Electric Vehicle Non-Demand Time-of-Day rate schedule, to a 3:1 price ratio for the Residential Service Electric

[211] Hr. Ex. 125, Ahrens Rebuttal, p. 24:17 – 24:20.
[212] Commissioner Megan M. Gilman does not join in these findings and conclusions.
[213] Hr. Ex. 101, Harrington Direct, p. 63:13 – 63:14.
[214] *Id.* at p. 66:1 – 19.

Vehicle and Small General Service Electric Vehicle schedules. BHCOE states that by making the price ratios more consistent, and reducing the 3:1 ratio, customers will be more likely to adopt TOU rates.

261. Staff does not oppose the 2:1 price ratio, stating that a 2:1 ratio is the minimum differential to provide a signal for conservation and shifting demand during the on-peak period. Although Staff states it would support a higher ratio in the summer period, it sees the benefits of consistency.[215]

262. UCA supports the 2:1 ratio, and favors making TOU rates attractive to customers and not so high to be viewed as punitive.[216]

263. We agree that consistency and simplicity are important aspects of TOU rate schedules in order to encourage customer adoption and find the 2:1 price ratio for all BHCOE TOU rate classes is appropriate for sending necessary price signals.

**(2) On-Peak Period**

264. BHCOE proposes an on-peak period of 4:00 p.m. to 8:00 p.m. during weekday/non-holiday days for all of its TOU rates and classes, consistent with its analysis of system peak hours.[217] Similar to the Company's current TOU price ratios, its current on-peak periods vary from class to class. BHCOE claims none of the on-peak periods currently offered actually align with current system peak hours.[218]

265. Staff also supports moving the on-peak period to 4:00 p.m. to 8:00 p.m. to better align with BHCOE'S load profile.

[215] Hr. Ex. 501, O'Neill Answer, p. 44:3 – 44:7.
[216] Hr. Ex. 301, England Answer, p. 41:9 – 41:12.
[217] Hr. Ex. 110, Hyatt Direct, p. 28:12 – 28:15.
[218] *Id.* at p. 28:8 – 28:12.

266. UCA recommends maintaining the current on-peak period from 3:00 p.m. to 7:00 p.m. UCA contends that maintaining the current period will reduce customer confusion, noting that all communication from the Company regarding TOU rates up to this point has been focused on the peak ending at 7:00 pm.[219] UCA is also concerned that a later on-peak period would make TOU rates less desirable and asserts that the current on-peak period ending at 7:00 p.m. allows customers to take advantage of an extra hour to make their homes comfortable prior to going to bed.[220] UCA cites the Company's analysis in noting that the 6:00 p.m. to 7:00 p.m. hour has a higher peak than the 7:00 p.m. to 8:00 p.m. hour for 11 months in 2023.[221]

267. We find an on-peak period of 5:00 p.m. to 8:00 p.m. during weekday/non-holiday days for all TOU rates and classes is appropriate and direct BHCOE to use this period as its on-peak period for all TOU rate schedules. We are concerned that an on-peak period that includes most of the evening hours could be a reason for customers to reject TOU rates. A three-hour window provides a price signal to customers, while still giving people enough room to fit TOU rates into their lives. In addition, as solar generation becomes more prevalent in BHCOE's service territory, the 4:00 to 5:00 pm hour will likely become less of a concern relative to later evening hours.[222]

**(3) Opt-In v. Opt-Out**

268. BHCOE proposes opt-in TOU rate schedules, noting that the Company's opt-out proposal in its Residential TOU pilot program in Proceeding No. 18A-0676E was rejected, with

[219] Hr. Ex. 301, England Answer, pp. 37:20 – 38:2.
[220] *Id.* at p. 38:10 – 38:13.
[221] *Id.* at pp. 40:13 – 41:6.
[222] Commissioner Megan M. Gilman does not join in these findings and conclusions.

the Commission finding that "many particular challenges and issues … would need to be overcome and resolved before proceeding to implement residential time-of-day rates in Pueblo."[223]

269. Staff and EOC also support the Company continuing to have TOU rates as an opt-in program. Staff notes that more education on TOU rates is necessary before the Company moves to TOU rates as a default. EOC suggests that the 15-minute interval or hourly customer usage data be available in order to assess energy patterns and analyze the impact of TOU rates on income qualified customers; EOC does not support mandatory TOU rate implementation until such an analysis can be performed.[224] EOC cites to several challenges with the Public Service TOU rollout of opt-out TOU rates including negative customer sentiment and reduced trust, particularly with IQ, retired, and disabled customers.[225]

270. UCA supports an opt-out TOU rate, stating that there must be a critical mass of customers participating in TOU rates to successfully put downward pressure on the need for long term investments, and that opt-in rates would lead to fewer customers on TOU rates than an opt-out option. UCA also points out that opt-out rates still do leave the ability for customers to choose to be on a flat rate.[226]

271. Additionally, EOC recommends the Commission require the Company to provide anonymized 15- or 60-minute interval usage data, specifically by zip code, as part of a future filing to inform broader TOU implementation.[227] UCA supports this proposal.

272. We find that an opt-in TOU rate structure is appropriate at the current time. While more broadly, a movement to TOU rates should provide long-term system savings and send

[223] Hr. Ex. 101, Harrington Direct, pp. 64:17 – 65:3.
[224] Hr. Ex. 600, Bennett Direct, pp. 28:18 – 29:7.
[225] EOC SOP at pp. 14-15.
[226] Hr. Ex. 600, Bennett Direct, pp. 28:18 – 29:7.
[227] EOC SOP at pp. 15-16.

accurate price signals to align customer behavior with system costs, implementing such as an opt-out rate at this particular time is unlikely to produce the desired outcomes. We agree with Staff's concerns regarding community engagement and note EOC's concerns regarding the impact of default TOU rates on IQ customers. As pointed out by EOC, "[TOU] rates represent a transformation in how utility customers perceive and respond to electricity rates."[228] This is BHCOE's first rate case in eight years, and with the communication and trust challenges between the utility and its customers as evidenced by the number and themes of public comments and as outlined by several parties in this Proceeding, communicating the rate increase alone will be a sizable lift—a mass switch to TOU rates at this time could serve to lead to further apprehension.

273. We had initially intended BHCOE to implement the TOU rates after summer 2025, noting that increased solar generation is likely to move BHCOE's system peaks to later in the evening and that customer education is important to encourage customers to opt into these rates. However, at the Technical Conference held on March 3, 2025, the Company noted that it currently has customers on TOU rates so delaying implementation of the rates authorized in this Proceeding would be problematic. Additionally, the Company expressed uncertainty as to what the Commission intended with the directive to implement the TOU rates "after Summer 2025." We direct BHCOE to implement the TOU rates approved in this Proceeding on March 22, 2025, along with its other tariff changes.[229] We acknowledge that the existing TOU rates are not designed to recover the revenue requirement established in this Proceeding so a delay in implementing the new TOU rates could be problematic.

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[228] *Id.* at p. 13.
[229] Chairman Eric Blank was not present at the March 5, 2025 CWM where this clarification was discussed.

274. We are concerned, however, that BHCOE's customers understand the changes to the TOU rates as soon as possible and direct the Company to prioritize education of these customers as to the changes in their rate structure. Additionally, we direct the Company to undertake education of all the Company's customers to ensure that they are aware of their option to switch to TOU rates and the potential benefits, for both the customers and the utility system, of opting in to TOU rates. This is particularly acute for customers who would have increased usage through investments in electrification and may pay higher rates under the IBR structure. Therefore, we also encourage the inclusion of information regarding a switch to TOU in marketing materials and rebates focused on beneficial electrification. We anticipate this customer-wide education would coincide with a goal to see more customers on TOU rates after September 2025.

275. Finally, given that the Company has advanced meter infrastructure ("AMI") meters fully deployed across its service territory,[230] and no party has expressed concern with or difficulty in fulfilling EOC's request, we direct the Company to provide this interval usage data by zip code, at either 15-minute or hourly intervals, in its next proceeding in which TOU rates are at issue.

**e. Customer Fixed Monthly Charge**

276. BHCOE proposes an increase in its fixed monthly customer charge for Residential, Residential Other, Small General Service, Large General Service, Large Power Service – Secondary, Large Power Service – Primary, Large Power Service – Transmission, and Irrigation Pumping. The Company characterizes the increases as cost-based, saying that they are reflective of the results of the Class Cost of Service Study as well as revenue mitigation.[231]

[230] Hr. Ex. 600, Bennett Answer, p. 28:18.
[231] Hr. Ex. 110, Hyatt Direct, p. 36:16 – 36:18.

The proposed monthly charge for standard Residential customers is $9.00 dollars per month, an increase of $0.23 from the current monthly charge of $8.77 a month.[232]

277. Staff does not oppose BHCOE's requested increases in its customer charge in this Proceeding.[233]

278. While UCA contends that the customer charge should be calculated solely on the direct cost necessary to connect and maintain a customer's account, in the interest of gradualism and rate continuity UCA recommends that the current fixed monthly customer charges be maintained for the Residential, Residential Other, and Small General Service classes.[234]

279. BHCOE states that, since its methodologies are consistent with cost causation and are consistent with the approval of those costs in prior proceedings, they can be used to produce just and reasonable rates in this Proceeding as well, and that UCA's methods are not needed for this Proceeding.[235]

280. We find that in the interest of rate stability, as well as affordability for low usage customers BHCOE's existing customer charges shall be maintained at this time. Further, considering the reductions to the Company's cost of service made in this decision, a CCOSS model that reflects this decision would produce lower customer charges than those the Company proposes.

281. We note that in its revised CCOSS as presented at the March 3, 2025 Technical Conference, the Company includes an increased customer charge for Residential Other, Small General Service, Large General Service – Secondary, Large General Service – Primary, Large Power Service – Secondary, Large Power Service – Primary, and Irrigation Pumping rate classes.

[232] The full list of proposed customer charges is shown in Hr. Ex. 123, Hyatt Rebuttal, Attach. DNH-22.
[233] Hr. Ex. 500, Sigalla Answer, p. 104:19 – 104:21.
[234] Hr. Ex. 305, Watkins Answer, p. 48:7 – 48:10.
[235] Hr. Ex. 123, Hyatt Rebuttal, p. 17:14 – 17:19.

282. We confirm that no increase in customer charge for any customer class has been authorized and direct the Company to revise its CCOSS accordingly.[236]

### 8. Additional Issues

#### a. Heat Pump Rate

283. WRA/SC encourages the Commission to require BHCOE to provide a heat pump rate, noting that SB 24-214 requires such a voluntary rate be filed on or before August 1, 2027. WRA/SC also recommends the Commission require BCHOE to collect data on participants in the voluntary heat pump rate and characteristics about their energy usage and demand.[237] WRA/SC argue that although the Company has until August 2027 pursuant to § 40-3.2-110(2), C.R.S., to establish a heat pump rate, this Proceeding offers an opportunity to begin educating customers and increase interest in a heat pump rate and to improve the economics of heat pump adoption in advance of the 2030 Clean Heat target set by § 40-3.2-108, C.R.S. WRA/SC also see this Proceeding, the first rate case since SB 24-214 was passed, as the appropriate venue to establish elements of an electric hearing rate design that will inform future utility rate proposals. Finally, WRA/SC suggest that the introduction of a voluntary heat pump rate for BHCOE customers will address the affordability of heat pumps and enable customer to access electrification incentives available through Public Service's Clean Heat Plan (the natural gas provider for some of BHCOE's service territory, including Pueblo).[238]

284. WRA/SC propose two potential heat pump rates: a flat seasonal heat pump rate for the summer and a seasonal TOU heat pump rate with a 1.5:1 rate differential for summer months from 4:00 to 8:00 pm.[239]

[236] Chairman Eric Blank was not present at the March 5, 2025 CWM where this clarification was discussed.
[237] Hr. Ex. 1100, Valentine Answer, p. 6:8 – 6:23.
[238] *Id.* at p. 14:6 – 15:21.
[239] Hr. Ex. 1101, Whited Answer, pp. 16:18 – 17:4.

285. BHCOE requests the Commission reject the heat pump rate proposals of WRA/SC and responds that its optional Residential TOU rate meets the requirements of SB 24-214 and is appropriate for all customers. The Company states that customers with heat pumps can pre-heat their homes prior to on-peak times in the same manner in which customers with central air conditioning can pre-cool their homes prior to on-peak times. The result is cost savings for heat pump customers.[240]

286. Staff recommends that WRA/SC's heat pump rates be rejected and raises concerns about having limited time to review the rate, since it was first introduced in Answer Testimony.[241] Staff expresses concerns that "boutique rates" inherently do not reflect cost causation[242] and has a number of specific concerns to the rate proposed by WRA/SC, including: revenue neutrality, the possibility of customers gaming the rate, and the rate not being developed using the full CCOSS process.[243]

287. We deny WRA/SC's proposed heat pump rates. SB 24-214 does not a require a filing with a heat pump rate until August 1, 2027, and thus it is unnecessary to put a heat pump rate in effect now at this early juncture without a record addressing additional aspects of a proposed rate. We agree with Staff that the rate should not be developed outside the scope of a full CCOSS and that the rates should be shown to be revenue neutral. We also agree with Staff that various rate design proposals in this Proceeding do offer heat pump customers some limited opportunity of savings.

288. However, we also agree with WRA/SC that the Company's Residential TOU rate is not sufficient to meet the heat pump rate requirement of SB 24-214. While it is true that the

[240] Hr. Ex. 123, Hyatt Rebuttal, pp. 24:13 – 25:2.
[241] Hr. Ex. 509, O'Neill Cross-Answer, p. 10:9 – 10:13.
[242] *Id.* at p. 9:6 – 9:17.
[243] *Id.* at pp. 10:15 – 14:10.

Residential TOU rate gives heat pump customers an opportunity to save money by changing usage behavior, that is no different for those customers than for any other residential customers. WRA/SC presents evidence that heat pump customers would actually, on average, pay more under the Residential TOU rate than the flat default rate proposed by the Company, which the Company did not dispute.[244] We note that one theme throughout this case has been the "denominator problem," with BHCOE's lack of new customers or sales growth resulting in higher rates; a true heat pump rate could encourage beneficial electrification, provide cost-justified savings to customers who improve their capacity factor, and provide downward rate pressure to the system as a whole. BHCOE's system also continues to distinctly peak in the summer months, so consistent winter and shoulder season sales in particular could benefit the system, further supporting the adoption of a heat pump rate.

289. Accordingly, we direct BHCOE to file a compliant rate proposal pursuant to SB 24-214 by the statutory deadline of August 1, 2027. The Company should invite all interested stakeholders, including the parties in this Proceeding, to participate in a stakeholder process at least 60 days before filing a heat pump rate. When BHCOE makes the filing, it should provide accompanying analysis showing that 1) the proposed rate will reduce heat pump customer bills, if cost-justified, while being revenue neutral for the entire class; and 2) provide testimony regarding whether the rate should be limited to only heat pump customers or available to all residential customers. Finally, we encourage seasonally differentiated rates to be considered as part of this analysis—seasonally differentiated rates can be another method to improve capacity factors through encouraging year-round usage via beneficial electrification.

[244] Hr. Ex. 1103, BHCOE Response to WRA/SC 4-2; *see also* Hr. Tr. December 5, 2024, pp. 164 - 165.

**b. Peak View Wind Facility DTA**

290. Staff raises a concern regarding the return the Company is applying to the Deferred Tax Asset ("DTA") associated with Peak View Wind Facility ("Peak View"), a 60 MW Company-owned generation facility approved in the Company's 2013 Electric Resource Plan ("ERP").

291. The Settlement Agreement approved in the Peak View CPCN proceeding[245] precludes inclusion of Peak View in base rates through 2026 so those costs are not included in this Proceeding. BHCOE collects avoided costs of Peak View through the ECA and TCA, with incremental costs above the avoided cost charged to the RESA. Staff states that although the project generates Production Tax Credits ("PTCs") whose value has been included in the revenue requirement, the PTCs have not actually been used, so a DTA of $39.6 million has been created.[246] Staff argues that the DTA was not considered during the ERP and CPCN proceeding,[247] thus was not contemplated to be included in the revenue requirement or as part of the prudency cost test established in the settlement agreement approved in Decision No. C15-1182.[248]

292. Staff contends that there DTA was not indicated in the 2016 and 2017 Annual Renewable Energy Standard ("RES") reports but beginning in 2018 the Company has applied a WACC return on DTA the revenue requirement included in recovery in the ECA and RESA. Although the Company contends it has been transparent about the DTA in its RES reports, Staff contends that its review of the RES reports is only to evaluate compliance with RES requirements

[245] Decision No. C15-1182 at ¶ 17 issued in Proceeding No. 15A-0502E on November 6, 2015.
[246] Hr. Ex. 501C, O'Neill Answer, pp. 24:2 – 25:5.
[247] Proceeding Nos. 15A-0502E; 13A-0445E.
[248] Hr. Ex. 501C, O'Neill Answer, p. 29:9 – 29:13.

and does not constitute Commission approval of a WACC return on the DTA.[249] Staff estimates rate payers have been charged $9.6 million to date.

293. Staff explains that prior to 2023, utilities could not sell or transfer PTCs, which often resulted in the creation of DTAs. After the enactment of the Inflation Reduction Act of 2022, PTCs generated after December 31, 2022, could be sold to tax equity partners.[250] BHCOE has indicated that it has begun transferring PTCs. but Staff estimates that ratepayers will pay some $13 million in carrying costs until the DTA is extinguished.[251]

294. In Answer Testimony, Staff recommends that as part of the Company's compliance filing in this Proceeding the Company file update its RESA accounting to remove the DTA and any associated earnings, reducing the ECA/RESA annual revenue requirement by more than $2 million. An additional $13 million would be made available to the RESA to be used for other purposes over the remaining life of the DTA.[252] In its SOP, Staff recommends the Commission direct the Company to cease applying a return on the Peak View DTA going forward.[253]

295. BHCOE responds that this is not the appropriate venue to examine Peak View because there are no costs associated with Peak View in this Proceeding. The Company offers that Staff can raise its concerns when the Company files its annual RES compliance report or in the Company's annual ECA prudency review. Additionally, in early 2026 BHCOE will file to extend or modify cost recovery for Peak View and Staff can raise its concerns at that time.[254]

296. BHCOE did not seek Commission authorization prior to applying the WACC to the DTA and we are concerned that it appears BHCOE has failed to fully monetize the tax credits for

[249] Staff's SOP at p. 58.
[250] *Id.* at p. 39:6 – 39:10.
[251] *Id.* at pp. 30:17 – 31:10.
[252] Hr. Ex. 501C, O'Neill Answer, p. 34:8 – 34:15.
[253] Staff SOP at p. 60.
[254] Hr. Ex. 116, Harrington Rebuttal (Rev. 1), p. 60:4 – 60:22.

years. Additionally, although the recovery of these costs is in the ECA, not in base rates that are the focus of this Proceeding,[255] in this combined Phase I and Phase II we are implementing rates that ultimately include recovery of ECA related costs and the Proceeding takes a holistic, general review of rates charged to customers. We find the policy question—whether it is appropriate to allow the Company to earn its WACC on the DTAs for the Peak View facility—has been fully litigated in this Proceeding. On the record developed by Staff that BHCOE has had an opportunity to fully respond to through its Rebuttal Testimony and at the evidentiary hearing, we find it is inappropriate for the Company to earn its WACC on the DTAs for the Peak View facility. While we decline to require a compliance filing in this Proceeding as requested by Staff, we order that BHCOE shall not charge its WACC on the DTAs for the Peak View facility in future years, and provide this policy guidance to the ALJ presiding over Proceeding No. 24A-0371E for implementation there as appropriate.

**c. Pueblo 5 and 6**

297. Staff and Pueblo raise the issue of Pueblo 5 and 6, retired coal-fired units that were granted decommissioning by the Commission in 2015. Black Hills states that environmental remediation was completed in January 2016 and that demolition of the building was delayed because the City of Pueblo deemed the structure an Historic Landmark.[256] Black Hills states that the facility has been retired and removed from the Company's books and records; in response to discovery in this Proceeding, the Company determined that a small portion of the land, which is shared with the Company's administrative offices, a substation, tool machine shop, and equipment

[255] Staff also raises this issue (at least regard to the 2023 ECA prudency review) in Proceeding No. 24A-0371E.

[256] Hr. Ex. 116, Harrington Rebuttal (Rev. 1), p. 91:18 – 91:21 and Attachment MJH-17.

laydown yard, should be removed from rate base. Accordingly, BHCOE removed $70,532 from rate base in the Company's Rebuttal revenue requirement request.

298. Staff suggests the Commission deny half of the $81,144 security costs associated with the area and deny any property tax expense, which Staff states it is unable to calculate. Black Hills argues that the security costs are necessary for its active buildings and employees on the site.

299. Pueblo contends that Black Hills has declined to provide information about contamination at the site so the site cannot be sold or re-developed. Pueblo witnesses suggest the Company should sell the site to the City of Pueblo for $1; Staff states that the Company should donate the property to the City.[257]

300. We decline to disallow $40,572 or property taxes associated with security for the area that includes Pueblo 5 and 6 as requested by Staff. We agree that with other Company facilities on the site it is important to ensure the safety of BHCOE employees. We also find that the issue of historic designation and redevelopment of the site is not within the scope of this rate case and decline to make any related findings.

#### d. Customer Bill Format

301. During the hearing the Company was asked questions regarding bill format, noting that the Company redesigned its bill in Proceeding No. 18M-0072E. In its SOP, the Company offers to restructure the "Glossary of Terms" page included in customer bills to align with the rates listed in the bill and to identify the components of the four categories of charges in the bill: Delivery and Distribution, Energy Supply, Other Costs, and Taxes. The Company states that

[257] Hr. Ex. 400, Shaw Answer, p. 21:3 – 21:5; Hr. Ex. 402 Graham Answer, p. 13:16 – 13:18; Hr. Ex. 500HC Sigalla Answer (Rev. 1), p. 204:13 – 204:15.

changes to the Glossary of Terms page can be more easily made than changes to the first two pages of customer bills which are consistent for all customers served by Black Hills affiliates. The Company suggests it could work on the bill format update with Staff, as it did in the 2018 proceeding.

302. We direct BHCOE work with Staff to make the changes suggested by BHCOE in its SOP to the customer bill.

**e. BHEAP Waitlist**

303. Staff and EOC raised the issue of a current waitlist for BHEAP assistance. EOC's Answer Testimony provides the latest count in the record of 140 customers on the list as of September 2024.[258] During the evidentiary hearing, in response to Commissioner Gilman's questions, Black Hills witness Harrington stated that it would take about $140,000 in additional BHEAP funds to include these customers in BHEAP. He suggested that the $140,000 could come from Commission approval to modify the BHEAP program cost recovery cap, or that the Company could raise the funding rates from other customer classes. He also noted that the Company itself recently contributed $450,000 to the fund.[259]

304. Black Hills is currently collecting from non-BHEAP customers monthly the $1.00 maximum allowed pursuant to Commission Rule 4 CCR 723-3-3412(g)(II)(B). In its SOP, EOC suggests granting Black Hills a temporary variance of the $1.00 cost recovery cap under Rule 4 CCR 723-3-3412(g)(II)(B). Under Rule 4 CCR 723-1-1003(a), the Commission may, for good cause shown grant variances from Commission rules by taking into account considerations of hardship, equity, or more effective implementation of overall policy on an individual basis

[258] Hr. Ex. 600, Bennett Answer, p. 13, fn. 13.
[259] Hr. Tr. December. 6, 2024, pp. 246-265.

305. We direct Black Hills within 60 days of a final decision in this Proceeding to file an advice letter with terms that will sufficiently address the current BHEAP waitlist and request for variance pursuant to Commission Rule 4 CCR 723-1-1003 of the $1.00 cost recovery cap under Rule 4 CCR 723-3-3412(g)(II)(B).

#### f. Receipt of Payments in Black Hills' Pueblo Office

306. Staff and Pueblo raise concerns about the availability of Black Hills administrative offices in Pueblo Specifically, both seek to ensure that the building is open and that customers can pay their bills inside the office. Staff raises a further concern about receipt of cash payments, contending that cash and credit card payments received by third parties are subject to service charges.

307. Staff recommends modifying Black Hills tariff Sheet R15 at 9.A. as follows:

> 9. Delayed Payment Charges:
> A. All bills for utility service are due and payable upon receipt. The Company shall accept payment at its Pueblo Office during normal business hours and the date of arrival at the BHCOE shall be deemed the payment date. A bill shall be deemed delinquent if payment thereof is not received by the Company or its authorized agent on or before the date stated on the bill which date shall be:
> 1. For all non-residential customers, the fifteenth (15th) day after date of billing.
>
> B When a bill becomes a delinquent; a late payment charge in an amount equal to one and one half percent (1.5%) of the delinquent amount owed for current non-residential utility service will be added to the customer's bill.

308. We agree with Staff that regular access to the Company's office for in person bill payment is necessary and direct BHCOE to modify its tariff accordingly as indicated above.

**g. Data Retention**

309. Staff requests the Commission direct BHCOE to modify its tariff to require retaining data for at least ten years or since the last rate review. Staff states that the Company was unable to respond to several data requests because BHCOE only maintains data as far back as 2019. Staff argues that Commission policy is for utilities to maintain data for ten years or since the last rate review.

310. We direct the Company to revise its tariff sheets, consistent with Staff's request, to indicate that data shall be retained for the longer of ten years or since the Company's last rate review.[260]

**h. Update to DSMCA**

311. BHCOE recovers the costs of its demand-side management programs through the DSMCA. The DSMCA is set forth in the Company's Colo. PUC No. 11 electric tariff on Sheets Nos. 68 through 71. The form of the DSMCA is a percentage surcharge, called the DSMCA Rider,

[260] Hr. Ex. 500HC, Sigalla Answer, p. 224:1-224:8.

calculated on Sheet No. 71 (set at 3.02 percent, effective January 1, 2025). Although Sheet Nos. 68 through 71 were not filed with Advice Letter No. 871, each of the base rate tariffs that were filed in this case list the DSMCA as an applicable rate adjustment when service is taken pursuant to that base rate.

312. The Company does not propose any change to its DSMCA in its Direct Testimony. However, Staff voices concern in Answer Testimony that if base rates increase substantially, the resulting increase DSMCA collections could be in excess of Commission approved DSM funding.[261] Staff recommends a recalculation of the appropriate percentage of DSMCA Rider in order to maintain the DSM funding at the appropriate level.

313. BHCOE responds that it does not object to Staff's proposal as it will eliminate any potential DSMCA overcollection but offers that another way to address the issue would be to include the effect of new base rates in the Company's April 1, 2025, DSMCA filing, which will be effective in July 2025.[262]

314. We find Staff has shown good cause for a directive to Black Hills to refile Sheet No. 71 of its DSMCA in accordance with the changes in projected sales revenue resulting from the final decision in this rate case. The updated Sheet No. 71 that was presented at the technical conference should be included in Black Hills' subsequent advice letter compliance filing. This will result in a timelier implementation of the required change in the DSMCA Rider, since the DSMCA filing to be made on April 1 is intended to adjust rates beginning July 1.

[261] Hr. Ex. 501C, O'Neill Answer, p. 54:10 – 54:17.
[262] Hr. Ex. 125, Ahrens Rebuttal, pp. 16:5 – 17:7.

**i. Net Metering**

315. In general, net metering is the offsetting of a utility customer's electricity consumption by the electricity generated from distributed energy resources. The Colorado General Assembly affirmed the requirement for Black Hills to offer net metering through the passage of SB 21-261. That statute replaced the "standard offer" approach that first required investor-owned electric utilities to offer net metering pursuant to Amendment 37 with a more generic requirement to offer a "net metering service." Unlike Public Service, Black Hills does not have a tariff setting forth terms and conditions for net metering. A few of the tariff sheets filed with Advice Letter No. 871 include the term net metering, but the context of its usage is primarily to address special terms and conditions for TOU rates.

316. Net metering is implemented by Black Hill largely pursuant to its Renewable Energy Standard compliance plan ("RES Plan"). The Company's latest RES Plan covers 2023-2026 and was approved in Proceeding No. 22A-0230E (BHCOE's combined 2022 ERP/CEP and 2023-2026 RES Plan) by Decision No. C23-0193.[263] The RES Plan addresses net metering where the customer receives an incentive from Black Hills in exchange for the RECs generated by the DERs as well as "net metering only," where there is no incentive paid and no exchange of RECs.

317. BHCOE reports in its Direct Testimony in this case that at the end of 2023, it had 7,739 residential net metered customers. The Company provides an "informational" CCOSS that the Company uses to illustrate the "impact of net metering."[264] Specifically, Black Hills estimates that in 2023 it "lost" some $3.5 million in fixed cost recovery from customers switching to net

[263] *See* Decision No. C23-0193 at ¶ ¶ 42-46 issued in Proceeding No. 22A-0230E on March 22, 2023 ("In the Matter of the Application of Black Hills Colorado Electric, LLC for (1) Approval of Its 2022 Electric Resource Plan and Clean Energy Plan, And (2) Approval of Its 2023-2026 Renewable Energy Standard Compliance Plan.").

[264] Hr. Ex. 110, Hyatt Direct, pp. 74:4 – 75:4; Hr. Ex. 110, Attach. DNH-13 Informational Class Cost of Service Study ("CCOSS I-1"); and Hr. Ex. 110, Attach. DNH-14 Informational Class Cost of Service Study ("CCOSS I-2").

metering. The Company calculates a fixed cost loss of about 410 kWh per month for each customer who switches to net metering because Company must maintain all facilities necessary to provide service to the customer, but it cannot recover those costs under the current net metering rate structure.

318. As explained in Decision No. C24-0669, issued on September 17, 2024, COSSA/SEIA filed a motion to strike or dismiss Black Hills' testimony related to net metering as one cause of the Company's revenue requirement deficiency. COSSA/SEIA recommends the Commission require the Company to present only one CCOSS in future rate cases that includes the residential customer class as a single class of customers and recommends the Commission disregard any testimony regarding cost shifts due to net metering or DERs. The Commission denied COSSA/SEIA's motion, stating that it would find it "beneficial to consider the whole of the information provided" given the magnitude of the requested increase in base rate revenues in this case. The Commission further stated that it will evaluate relevant evidence related to net metering and assign it the appropriate weight.

319. The only relief Black Hills seeks from the Commission at this time is to open a miscellaneous proceeding to explore potential alternatives to the current net metering billing arrangement.[265]

320. We note that it is not surprising to see BHCOE customers seeking relief from high rates through adoption of net metering and on-site solar, and we understand that this is a reasonable course of action for the customer.

321. We decline to open the miscellaneous proceeding BHCOE requests at this time due to the Commission's limited resources. We find it reasonable that certain BHCOE customers

[265] Hr. Ex. 116, Harrington Rebuttal, p. 71:9 – 71:10.

seeking relief from high rates will pursue net metering. We also understand BHCOE's rate impact concerns behind its request for the Commission to open a proceeding. Nevertheless, the Company failed to provide a sufficient analysis of its claims regarding the rate impacts from net metering, did no cost/benefit analysis of net metering to the system, and finally failed to demonstrate any difference in cost of service to net metered customers as compared to non-net metered customers. Further, the Commission's ability to extend to Black Hills the relief it may ultimately seek may be limited by statute Additional Authorizations

**j. Roll TCA and PCCA into Base Rates**

322. We authorize BHCOE to roll the TCA and PCCA costs into base rates and set the balance for these riders to zero, with incremental cost recovery beginning in 2024.

**k. Update Construction Allowance**

323. We authorize BHCOE to update its customer construction allowances, using the same methodology approved in the 2017 Phase II Rate Case.[266] As a result, Small Residential and Small General Service customers will receive a construction allowance that includes a fixed service lateral portion and a fixed distribution system component. Irrigation, Large General Service – Secondary and Large Power Service – Secondary customers will receive a fixed service lateral portion and a variable distribution system component based on their projected peak load. Customers in the Large General Service and Large Power Service classes will receive a variable distribution component based on their projected peak load. Traffic Signal Lighting will receive a construction allowance for distribution system at a fixed amount per point of delivery. Street Lighting – Company Owned and Private Area Lighting – Company owned will receive a construction allowance for service laterals at a fixed amount per unit.

[266] Decision No. R18-0054 at ¶ 312 issued Proceeding No. 17AL-0477E on January 23, 2018.

**l. Depreciation Study**

324. BHCOE contracted with Gannet Fleming Valuation and Rate Consultants, LLC for a new depreciation study that it provided in this Proceeding.[267] We authorize the depreciation rates proposed by BHCOE in this Proceeding.

**m. Requests of Parties not Discussed by the Commission**

325. BHCOE requests approval of several items that were not addressed by any intervening party. These uncontested requests of the Company are approved.

326. All contested requests of the parties not discussed by the Commission in this Decision, including requests of BHCOE contested by one or more of the intervening parties, are denied. All uncontested requests put forward by intervening parties not discussed by the Commission in this Decision are also denied.

**n. Quality of Service Plan (QSP) Filing**

327. Several intervenors raised concerns about the Company's QSP in Answer Testimony. Staff had specific questions about the QSP, Pueblo expressed concerns about the Company's customer service, and Cañon City discussed reliability issues.

328. Prior to the evidentiary hearing, BHCOE filed a notice of withdrawal of testimony addressing QSP issues and attached a stipulation reached between Staff and BCHOE regarding a QSP ("QSP Stipulation"). Within six months of a final decision in this Proceeding, Black Hills agrees to develop a QSP and share it with Staff and other interested parties. BHCOE also commits to stakeholder engagement, including two meetings to be held with interested parties to discuss the proposed QSP. The QSP will be filed with the Commission within 60 days of the plan's initial submittal to Staff and other parties.

[267] *See* Hr. Ex. 109, Attach. JJS-2 "2023 Depreciation Study."

329. The QSP Stipulation between Staff and BHCOE requires the QSP to address performance metric goals and penalties for non-performance. Additionally, the QSP is expected to address telephone response time, customer complaint numbers, "Customers Experiencing Multiple Outages" "Customers Experiencing Long Interruptions," and streetlighting. Customers experience data at the census block group level is expected in order to evaluate intra-territorial service parity. BHCOE reserves the right to include or exclude any of these issues.

330. At the evidentiary hearing, the Commission requested that BHCOE file the QSP Stipulation which was attached to its November 22, 2024 notice filing as a motion pursuant to Commission Rules 4 CCR 723-1-1400 and 1407. On December 3, 2024, BHCOE filed a written Motion for Approval of the Stipulation with Trial Staff Regarding a QSP which incorporated the QSP stipulation originally filed on November 22, 2024.

331. We grant the Motion for Approval of the Stipulation with Trial Staff Regarding a QSP.

### o. Future Capital Spending Concerns

332. The record in this case showed that the Company's capital spending averaged roughly $35 million per year from 2016 to 2021.[268] This disciplined capital spending appears to be one of the significant factors that enabled the Company to avoid raising rates since 2016. In 2022, the Company's capital spending increased to over $60 million and by 2023 over $90 million.[269] This increased capital spending seems to be one of the single biggest drivers of the current rate increase request and expanded rate base by over 60percent since the last rate case filing in 2016.[270] This record also seems clear that the Company intends to continue to maintain these high levels of

[268] See Hr. Ex. 101, Harrington Direct Testimony, Table MJH-3, at p. 30.
[269] *Id.*
[270] Hr. Tr. December 4, 2024, p. 33: 17- 33:20.

capital spending over the next five years in ways which could make another rate increase request likely in the not too far distant future.[271]

333. Given these realities, the Commission hereby asks both the Company and Staff to present a long-term residential rate forecast that helps us better understand the relationship between capital spending, revenue growth, and potential rate impact in the upcoming Distribution System Plan[272] and Rule 3206 Transmission Cost Adjustment filings[273] including identifying limits on the level of capital spending that would be required to keep rates growing no faster than inflation. The Commission would also request that the Company present a five-year transmission capital spending budget in its Rule 3206 TCA filing expected in April. Overall, the goal of these requests is to better understand how much capital can be spent without raising rates above inflation and exploring ways to avoid another large rate increase request.

**D. Conclusion**

334. We have carefully reviewed the extensive evidentiary record in this Proceeding, mindful of the public comments submitted in writing and offered orally at the public comment hearings on October 29 and 30, 2024, November 19, 2024, and December 5, 2024.

335. Based on this review of the evidentiary record, our consideration of the SOPs filed by BHCOE and the intervening parties, and our deliberations, we establish new rates to recovery the Company's expenses and provide the Company a reasonable opportunity to earn a fair rate of return.

336. The new rates, terms, and conditions of service filed by BHCOE with Advice Letter No. 871 as modified by this Decision are just, reasonable, and non-discriminatory.

[271] Hr. Tr. December 2, 2024, pp. 288-292 (discussing the Hearing Exhibit 1500, the Black Hills November 2024 and the five-year capital spending plan).
[272] Proceeding No. 25A-0062E.
[273] Anticipated Pursuant to Commission Rule 3206(d) by April 30 annually.

337. We permanently suspend the tariff sheets filed with Advice Letter No. 871 and cause an effective implementation date of March 22, 2025 for new rates, terms, and conditions for service established by this Decision. In lieu of the rate and other tariff changes originally proposed in the tariff sheets filed with Advice Letter No. 871, BHCOE shall make a compliance advice letter filing on not less than two business days' notice to place the new rates, terms, and conditions for service into effect on March 22, 2025.

338. The tariffs field by BHCOE with Advice Letter No. 871 on June 14, 2024, will be permanently suspended, and will not become effective.

**E. Compliance procedures**

339. BHCOE shall file an advice letter compliance filing to modify the tariff sheets in Colorado PUC No. 11 consistent with the findings, conclusions, and directives in this Decision.

340. For the rates, terms, and conditions approved for effect March 22, 2024, BHCOE shall file the compliance tariff sheets in a separate proceeding and on not less than two business days' notice. The advice letter and tariff sheets shall be filed as a 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.

341. BHCOE shall include its updated DSMCA Sheet No. 71 as presented at the Technical Conference should be included in its advice letter compliance filing.

342. Within 60 days of a final decision in this Proceeding, BHCOE shall file an advice letter with terms that will sufficiently address the current BHEAP waitlist and request for variance

pursuant to Commission Rule 4 CCR 723-1-1003 of the $1.00 cost recovery cap under Rule 4 CCR 723-3-3412(g)(II)(B).

## II. ORDER

### A. The Commission Orders That:

2. The effective date of the tariff sheets filed by Black Hills Colorado Electric, LLC, doing business as Black Hills Energy ("BHCOE" or "Company"), on June 14, 2024, with Advice Letter No. 871 ("Advice Letter 871") is permanently suspended and shall not be further amended.

3. The tariff sheets filed with Advice Letter No. 871 are permanently suspended and shall not be further amended.

4. In accordance with the discussion above, BHCOE shall file advice letter compliance filings to modify the tariff sheets in Colorado PUC No. 11 consistent with the findings, conclusions, and directives in this Decision.

5. The Motion for Approval of the Stipulation with Trial Staff Regarding a Quality of Service Plan, filed by BHCOE on December 3, 2024, is granted.

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 Issued Date.

**B. ADOPTED IN COMMISSIONERS' WEEKLY MEETINGS:
February 12 and 19, 2025, and March 5 and 12, 2025.**

(S E A L)

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK

TOM PLANT

Commissioners

ATTEST: A TRUE COPY

Rebecca E White

Rebecca E. White,
Director

COMMISSIONER MEGAN M. GILMAN
DISSENTS, IN PART

## III. DISSENT OF COMMISSIONER MEGAN M. GILMAN

1. While I respect the intent of the majority to ensure that new rates do not further disadvantage income-qualified customers, the rationale and resulting decision to keep an inverted block rate as the default rate for all residential customers is not supported by compelling evidence on this record and is inconsistent with other state policy objectives. First and foremost, the advocacy that Black Hills and Staff put forth that inclining block rates are not well aligned with cost causation, fairness, equity, ease of understanding and beneficial electrification policy were all appropriate and significant reasons to move on from this rate design. More importantly, regardless of whether the record demonstrates purported benefits of IBR rates to IQ customers, retaining it as the default rate for all customers is far too broad of a solution.

2. The majority retains the inclining block rate as the default based on concerns raised by EOC that IQ customers could be disadvantaged. However, the evidence that inverted block rates are more advantageous for income-qualified customers is thin and contradicted in this record. I do not find EOC's evidence compelling in light of the contrary evidence presented by BHCOE. EOC advocates that inverted block rates may be more advantageous than a flat rate structure for income-qualified customers, however, this position was contradicted by data provided in the record by BHCOE, which showed the opposite. While it is possible that Black Hills' analysis is not perfect and misses some income-qualified customers, it is the most detailed look available on this record, and shows that in every month evaluated in 2023, income-qualified customers participating in the Black Hill Energy Affordability Program actually used *more energy* than other residential customers. It is a possibility that these customers have a different price signal, as Mr. Bennett suggests, but it is also possible that other factors, like inefficient building envelopes and equipment, could be to the cause of higher usage for these customers. The connection that EOC

tries to draw here is weak and unsupported by sufficient data to draw the conclusion that it requests us to draw.

3. Even if EOC's evidence of benefits to IQ customers is compelling to the majority, it is unclear why such a determination should then be stretched to apply this as the default rate to all residential customers. EOC's advocacy does not answer why, if allowed to still be offered as it requests, the inverted block rates should be a default rate for *all* residential customers, rather than an option that income-qualified or other customers could choose in order to gain the savings they suggest may be available. We need not slow or prevent advancement of other important policy goals by retaining an antiquated rate structure for all customers to the benefit of a few that could be helped by a more targeted solution.

4. While the record does not point to any distinct advantage related to economics or other policy objectives that would indicate an inverted block rate would provide the most optimal outcomes (either for customers or for the system as a whole), it is rife with distinct disadvantages. Moving away from inclining block rates is necessary both to lower rates in the long term and to move forward with state clean energy goals. In order to achieve the state's ambitious and legislatively mandated climate goals,[274] significant beneficial electrification will be needed. While beneficial electrification is intended to save customers money on other fuels, it does increase the amount of electricity that they use. Beneficial electrification is an essential tool to achieve greenhouse gas reductions from transportation and buildings, but also provides a distinct opportunity to increase electric sales. A rate that disadvantages larger residential users stands as a direct impediment to beneficial electrification of vehicles, buildings, and other uses, because the economics of switching to electric end uses will be poorer than they would otherwise be on a flat

[274] 25-7-102, C.R.S.

rate. Customers who electrify may choose to opt in to a time-of-use rate or enroll in a future voluntary heat pump rate, as required by SB 24-214, and those rates may offer a significant cost saving over the inverted block rate. However, enrolling in an optional rate requires a level of interest and proactive action that we know the vast majority of customers generally will not or cannot exercise. Further, voluntary rates needed to support state policy can only be as successful as the provider's efforts to educate and market alternative options. While I am hopeful that customers who electrify may take voluntary service under one of these other tariffs, I have great concern that continuing this inverted block rate as the default will provide a significant impediment to beneficial electrification, putting at risk the potential to hit state policy goals around decarbonization and beneficial load growth which could lower rates in the longer term.

5. Compelling testimony from both Black Hills and Staff also indicate that an inverted block rate does not follow principles of cost causation. By not providing cost reflective rates, we risk sending the wrong price signal to customers, potentially causing the system to get more rather than less expensive. In addition to increasing sales, beneficial electrification of transportation and heating needs can add load at times when the system is not peaking, which could even provide downward pressure on rates over time. Lower or steady rates over the longer term have the ability to help all customers, including IQ customers. While the majority may believe that an IBR rate helps IQ customers in the short term, ensuring that rates align with cost causation principles and support state policy towards BE advancement offer more long-term solutions to assisting IQ customers over time.

6. I also disagree with the majority's selection of a time period for the voluntary residential time-of-use rate. Time-of-use rates should be user-friendly and easy to understand, but as a foundational principle, it is also essential that they be designed to address the system peaks,

which drive substantial investment in the electric system. The majority's decision to exclude the 4-5 p.m. hour is concerning because it deviates from the data in this record around system peak without a sufficient justification or record support. The evidence in this record shows that the current system peaks on summer afternoons between 4-5 p.m. While it is a fair expectation that this may shift later as increasing amounts of solar are added to the system, it may not be reasonable for the 4-5 p.m. timeframe to disappear completely as an hour of concern. Further, with a peak period starting at 5 p.m., customers may be naturally inclined to move their usage immediately before or after the peak window, meaning that through this rate design, the system may stand to see *increased* usage during its current peak, which would be an incredibly unfortunate outcome of a rate that should be designed to produce the opposite outcome. Further, no party in this Proceeding advocated for a peak period shorter than four hours, nor for a time period that excludes the crucial 4-5 p.m. hour. The record lacks any evidence that would support the selection of this time period or duration as being appropriate or advantageous for the system.