Decision No. C24-0117

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 23AL-0243E

IN THE MATTER OF ADVICE LETTER NO. 1923 - ELECTRIC FILED BY PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO P.U.C. NO. 8 - ELECTRIC TARIFF TO PLACE INTO EFFECT REVISED BASE RATES AND OTHER AFFECTED CHARGES FOR ALL ELECTRIC RATE SCHEDULES BY ELIMINATING THE GENERAL RATE SCHEDULE ADJUSTMENT (GRSA) AND GENERAL RATE SCHEDULE ADJUSTMENT - ENERGY (GRSA-E) AS WILL BE ESTABLISHED BY THE COMMISSION IN PROCEEDING NO. 22AL-0530E, TO INITIATE TIME-DIFFERENTIATED GENERATION AND TRANSMISSION DEMAND CHARGES FOR SECONDARY GENERAL SERVICE (SCHEDULE SG) AND SECONDARY GENERAL CRITICAL PEAK PRICING SERVICE (SCHEDULE SG-CPP), TO INTRODUCE NEW ELECTRIC VEHICLE RATE OPTIONS FOR CUSTOMERS TAKING SERVICE AT THE PRIMARY DISTRIBUTION LEVEL, TO ADJUST THE PRIMARY GENERAL CRITICAL PEAK PRICING AND SECONDARY PHOTOVOLTAIC TIME-OF-USE SERVICE SECTION TIME-DIFFERENTIATED DEMAND CHARGES, TO MAKE SEVERAL ADMINISTRATIVE REVISIONS, AND TO RECEIVE APPROVAL OF DEFERRED ACCOUNTING TREATMENT FOR RATE CASE EXPENSES, TO BECOME EFFECTIVE JUNE 15, 2023.

COMMISSION DECISION PERMANENTLY SUSPENDING TARIFF SHEETS AND ESTABLISHING RATES

Mailed Date: February 23, 2024
Adopted Date: February 7, 2024

I. <u>BY THE COMMISSION</u>

A. Statement

1. On May 15, 2023, Public Service Company of Colorado (Public Service or the Company) filed Advice Letter No. 1923-Electric with tariff sheets setting forth its base rates for retail electric utility service. The Class Cost of Service Study (CCOSS) used in this Phase II proceeding as the basis for new base rates reallocates among Public Service's major customer classes the revenue requirement established in Public Service's recent 2022 Phase I rate case (Proceeding No. 22AL-0530E). With the rates established by this Decision, the existing General Rate Schedule Adjustment (GRSA) and General Rate Schedule Adjustment - Energy (GRSA-E) will be eliminated.

2. By this Decision, the Commission permanently suspends the tariffs filed with Advice Letter No. 1923-Electric on May 15, 2023, and orders Public Service to file compliance tariffs with new base rates for retail electric utility service consistent with the findings, discussion, and conclusions in this Decision.

B. Procedural History

3. On May 15, 2023, Public Service filed Advice Letter No. 1923-Electric, accompanying tariff sheets, and supporting testimony and attachments.[1] The proposed effective date of the tariff sheets was June 15, 2023.

4. In previous Commission Proceeding No. 21AL-0317E, the Commission authorized Public Service to file a Phase II rate case prior to the conclusion of its 2022 Phase I rate case.[2] Public Service witness Jeffrey Knighten states that Public Service filed this Phase II rate case so that the final rate design in this Proceeding can incorporate test year revenue requirement and billing determinants of the 2022 Phase I rate case and better allocate stakeholder resources between the Phase I and Phase II proceedings.

5. On May 18, 2023, Public Service filed an Amended Advice Letter No. 1923-Electric and accompanying tariff sheet correcting the issue day and proposed effective date.

6. On May 24, 2023, the Colorado Office of the Utility Consumer Advocate (UCA) filed a protest and notice of intervention as of right, and requested the matter be suspended and set for evidentiary hearing.

7. By Decision No. C23-0373, issued June 5, 2023, pursuant to § 40-6-111(1), C.R.S., the Commission set for hearing the tariffs filed with Advice Letter No. 1923-Electric and thereby suspended their effective date for 120 days from the proposed effective date, or until October 13, 2023.

[1] By Decision No. C23-0349-I, the Commission granted Public Service's motion to use alternative forms of notice to alert affected customers of its filing. On June 2, 2023, Public Service filed an affidavit confirming the legal notice had been published in the Legal Classified Section of *The Denver Post* on May 22 and 29, 2023.

[2] Proceeding No. 21AL-0317E, Decision No. C22-0724.

8. On June 12, 2023, Trial Staff of the Colorado Public Utilities Commission (Staff) filed a notice of intervention as of right and request for hearing.

9. By Decision No. C23-0471, issued July 24, 2023, the Commission acknowledged the interventions as of right filed by Staff and UCA. In addition, the Commission granted the requests for permissive intervention that were timely filed by the Colorado Energy Consumers (CEC),[3] the City of Boulder (Boulder), the City and County of Denver, Climax Molybdenum Company (Climax), the Colorado Solar and Storage Association (COSSA) and the Solar Energy Industries Association (SEIA) (jointly, COSSA/SEIA), Energy Outreach Colorado (EOC), the Federal Executive Agencies (FEA), The Kroger Co. on behalf of its King Soopers and City Market Divisions (Kroger), Molson Coors Beverage Company (Molson Coors), Southwest Energy Efficiency Project (SWEEP), Walmart Inc., and Western Resource Advocates (WRA). The Commission also granted the requests for *pro hac vice* appearance filed by Kurt J. Boehm on behalf of Kroger, George Cavros on behalf of WRA, and Thomas Jernigan and Captain Marcus Duffy on behalf of the FEA.

10. By Decision No. C23-0483-I, issued July 26, 2023, the Commission directed Public Service to file Supplemental Direct Testimony addressing the on-peak, off-peak, and shoulder periods for its time-of-use rates.

11. By Decision No. C23-0556-I, issued August 21, 2023, the Commission granted Public Service's May 15, 2023 motion requesting extraordinary protection of certain claimed highly confidential information relating to customer information.

[3] CEC members include: AirGas, USA, LLC, All Recycling, Inc., the Colorado Hotel & Lodging Association, Lockheed Martin Corporation, Occidental Energy Ventures, Suncor Energy (U.S.A.) Inc., Western Midstream, and Google, Inc.

12. By Decision No. C23-0565-I, issued August 24, 2023, the Commission adopted the procedural schedule proposed by the parties and granted the Motion for Variance from Decision No. C23-0483-I filed by Public Service on August 4, 2023, thereby modifying the directives related to the Company's required Supplemental Direct Testimony. In addition, pursuant to § 40-6-111(1), C.R.S., the Commission suspended the effective date of the tariff sheets filed with Advice Letter No. 1923-Electric for an additional 130 days, or until February 20, 2024.

13. By Decision No. C23-0571-I, issued September 12, 2023, the Commission granted the request for *pro hac vice* appearance filed by Major Leslie Newton and Captain Ashley George on behalf of the FEA.

14. By Decision No. C23-0710-I, issued October 19, 2023, the Commission established hearing procedures and set requirements for the presentation and submission of exhibits at the hearing.

15. The evidentiary hearing on the tariffs was held before the Commission *en banc* on December 11, 12, 14, and 15, 2023. The following exhibits were admitted into evidence during the course of the hearing: Hearing Exhibit No. 1700 (the spreadsheet listing the most recent versions of pre-filed electronic hearing exhibits) and the pre-filed electronic testimonies and attachments listed in the exhibit. Also admitted during the hearing: Hearing Exhibit 101 and Attachment JRK-3, Hearing Exhibit 109 Rev. 1, Hearing Exhibit 109 Attachment DSK-11 Rev. 1, Hearing Exhibit 111, Hearing Exhibit 112, Hearing Exhibit 113, Hearing Exhibit 114, Hearing Exhibit 115, Hearing Exhibit 400, Hearing Exhibit 401, Hearing Exhibit 402, Hearing Exhibit 405, Hearing Exhibit 503, Hearing Exhibit 601 Rev. 1, Hearing Exhibit 601 Rev. 2, Hearing Exhibit 604, Hearing Exhibit 606, Hearing Exhibit 608, Hearing Exhibit 609, Hearing Exhibit 626, Hearing Exhibit 628, Hearing Exhibit 632, Hearing Exhibit 700 Rev. 2, Hearing Exhibit 701

Rev. 1, Hearing Exhibit 800 Rev. 2, Hearing Exhibit 800C Rev. 2, Hearing Exhibit 805, Hearing Exhibit 807, Hearing Exhibit 809, Hearing Exhibit 1402, Hearing Exhibit 1404, Hearing Exhibit 1405, Hearing Exhibit 1502, Hearing Exhibit 1503, and Hearing Exhibit 1802.

16. On January 16, 2024, the following parties filed statements of position (SOPs): Public Service, Boulder, CEC, Climax, COSSA/SEIA, EOC, FEA, Kroger, Staff, SWEEP, UCA, Walmart, and WRA.

17. Three written public comments were filed in this Proceeding. Of the comments, two raised general concerns with any further increases in Public Service's rates and one raised concern with implementation of time-of-use rates. Public comments in this proceeding are submitted for the Commission's general information and to encourage the Commission to exercise discretion in the matter. Additionally, particularly when received earlier in the proceeding, parties to the proceeding that present evidence might inform their presentation based upon comments received. The Commission's administrative record including all comments is publicly available.

18. The Commission deliberated at its February 7, 2024 Commissioners' Weekly Meeting, resulting in this Decision.

C. Discussion and Findings

1. The Rate Setting Process

19. Rates and charges for public utility service are to be just and reasonable pursuant to § 40-3-101(1), C.R.S. The Colorado Supreme Court has held it is the primary purpose of utility regulation to ensure that the rates charged for utility service are not excessive or unjustly discriminatory.[4] Further, § 40-3-101(2), C.R.S., requires a utility to provide such service and

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

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.

20. 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.[5] The Commission is an administrative agency of the legislature,[6] charged with the authority, and duty, to regulate the rates of public utilities operating within Colorado. *See* § 40-3-102, C.R.S. (vesting in the Commission the power to regulate all rates, charges, and tariffs of every public utility in this state and to do all things necessary or convenient in the exercise of such power); Colo. Const. Art. XXV (affirming General Assembly's power to regulate public utility facilities, service, and rates and charges, and delegating that power in all respects to the Commission); *Miller Brothers v. Pub. Utils. Comm'n*, 185 Colo. 414, 525 P.2d 443, 451 (1974) (holding Commission has as much authority as General Assembly possessed prior to adoption of Art. XXV in 1954, unless and until General Assembly enacts specific statutory restriction on Commission's authority, which then controls).

21. In the ratemaking process, the Commission necessarily exercises much judgment and discretion.[7] As the Colorado Supreme Court has long recognized:

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

[5] *Colorado-Ute Elec. Ass'n, Inc. v. Pub. Utils. Comm'n*, 760 P.2d 627, 638 (Colo. 1988); *see also Integrated Network Servs., Inc. v. Pub. Utils. Comm'n*, 875 P.2d 1373, 1381 (Colo. 1994) ("[I]t is the function of the [Commission] to adopt rate structures that are fair and reasonable.")

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

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

> of whether the rate order 'has passed beyond the lowest limit of the permitted zone of reasonableness into the forbidden reaches of confiscation.'[8]

Because of the level of judgment required, the Commission "may set rates based on the evidence as a whole" and "need not base its decision on specific empirical support in the form of a study or data."[9] The Colorado Supreme Court has described the Commission's evaluation as "a stream bounded on each side by the limits of discretion" and instructed reviewing courts to determine whether the Commission's end result stayed within its discretionary channels.[10]

22. When the Commission establishes rates, it is the result reached, not the method employed, that determines whether a rate is just and reasonable.[11] When ratemaking, the Commission applies regulatory principles and methods to determine a utility's revenue requirement. The Colorado Supreme Court has noted that "[s]ince rate setting is a legislative function which involves many questions of judgment and discretion, courts will not set aside the rate methodologies chosen by the [Commission] unless they are inherently unsound."[12] Further, "the [Commission] is not bound by a previously utilized methodology when it has a reasonable basis, in the exercise of its legislative function, to adopt a different one."[13] In ratemaking as well as other matters, the Commission is not bound by its prior decisions or by

---

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

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

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

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

[12] *CF&I Steel, L.P. v. Pub. Utils. Comm'n*, 949 P.2d 577, 584 (Colo. 1997); *see also Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 602 (1944).

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

any doctrine similar to *stare decisis.*[14] The appearance of arbitrariness is dispelled when new findings are made on the basis of new evidence and a new record.[15]

23. Our decision-making here in this Phase II rate case is consistent with our broad ratemaking authority and these longstanding legal principles.

2. Production Plant Allocation

24. Public Service has used the four coincident-peak (4CP) average and excess demand (AED) cost allocation methodology (4CP-AED) for decades, but the Company's last Phase II rate case, Proceeding No. 20AL-0432E, was the first Phase II proceeding in which the Company's wind resources, specifically Rush Creek Wind Farm, were included in the cost allocation methodology. In that case, the Company allocated its Rush Creek Wind Farm costs on a fully energy basis, contending this was appropriate because Rush Creek Wind Farm's wind resources benefit the Company's portfolio. The parties to that proceeding filed a settlement, requesting the Commission rule on the appropriate cost allocation methodology. The Administrative Law Judge conducting the rate case declined to rule on the cost allocation methodology. The Commission upheld the Administrative Law Judge's decision on exceptions, but concluded:

> While the Rush Creek Wind Farm provides primarily energy benefits to the grid, it represents the beginning of likely future generation asset investment. We agree that Public Service should develop mechanisms to allocate generation assets on a consistent basis. As a result, we direct the Company to file, as part of its next Phase II rate case, an alternative CCOSS methodology with the goal of applying more consistent allocation treatment across all electric generation and storage assets.[16]

[14] *Colorado-Ute,* 198 Colo. at 540–41, 602 P.2d at 865.
[15] *Id*.
[16] Proceeding No. 20AL-0432E, Decision No. C21-0536 at ¶ 47.

a. POD-PH and POD Methodologies

(1) Public Service Proposal

25. In response to the Commission's directive in Public Service's last Phase II rate case, Public Service proposes in this case to use a probability of dispatch (POD) - peak hours (PH) (POD-PH) methodology. Public Service explains that it chose this methodology because it offers consistent allocation across generation and storage assets, and it provides stability in the resulting class cost responsibilities. Public Service adds that this methodology will also evolve as resources, load, and dispatch change over time.

26. POD-PH allocates costs based on which generating units are expected to run during the top 1,000 load hours, base rate costs of the units, and customer class share of load in each of those hours. Public Service supports this methodology as one that allocates the cost of resources based on class usage during each of the top 1,000 hours and that can be applied across all generation assets currently in rate base and those that could be added in the future. The use of peak hours with the PH has not been approved for any other jurisdiction nationally, but Public Service defends its choice, stating that if all hours were used, as in POD using all 8,760 hours of the year, the result would allocate costs during periods of low load when renewable energy production could be curtailed.

27. Public Service maintains the use of 1,000 peak hours is an improvement upon the 4CP-AED methodology because changes in the four coincident peak demand hours of 4CP-AED can significantly alter class cost responsibilities. Public Service also reasons that, because POD-PH is seasonally agnostic, it is a better methodology as increased electrification is expected to shift customer load and system dispatch into the winter over the coming years. Public Service

states the cost allocations resulting from the POD-PH methodology are consistent with rate case outcomes in 2016 and 2020, despite use of a different cost allocation methodology.

28. Public Service cautions that the POD methodology, without peak hours, is essentially a 100 percent energy allocator and that class cost responsibilities are changed so that the Residential customer class sees a decline in cost responsibility that is inconsistent with its energy usage and growing peak demand.[17]

29. In its Rebuttal case, Public Service made the following changes to its proposed cost allocation, based on the positions in intervenors' Answer testimony:

- Use of the 4CP-AED allocator for transmission and distribution substation costs.
Public Service states that although it has traditionally used the same allocation methodology for generation, transmission, and distribution, class coincident peak demand during the summer months is a key driver for transmission and distribution investment, warranting the use of 4CP-AED. The Company states this can be further reviewed in its next Phase II rate case. This had minimal impact on the allocator.

- Hourly class loads updated to align with 2022 Test Year.
This had minimal impact on the allocator.

- Adjustment of allocation of production costs to account for EVRAZ's transition.
Public Service made adjustment to this allocation to account for the transition of its customer, CF&I Steel, L.P. doing business as EVRAZ NA, from an all-requirements electric customer to a net metered customer in Proceeding No. 18A-0569E. The result was a $5 million reduction in cost responsibility for C&I Transmission, which was shifted to other rate classes.[18]

30. In response to comments from CEC, Public Service agreed that production tax credit benefits associated with wind should be allocated in same manner as production plant costs, stating that if, as a result of this Proceeding, the allocation of Company-owned wind fixed production plant changes from the existing energy allocation, the Company will make a change in

[17] Hrng. Exh. 108 Knighten Rebuttal Testimony at 24:6-14.
[18] Hrng. Exh. 109 Klingeman Rebuttal Testimony at 18, Table DSK-R-4.

its Electric Commodity Adjustment to allocate production tax credit benefits in the same way. Public Service states this will result in a decrease for the Residential and Small Commercial classes and an increase for other classes.[19] The Company notes the production tax credit allocation should only be adopted if the Commission also adopts the CCOSS set forth in the Company's Rebuttal case.

31. In response to concerns raised by COSSA/SEIA in Answer testimony, Public Service revised the weightings for different meter types, acknowledging that the Advanced Metering Infrastructure (AMI) meter category was introduced in this case. Noting that the initial staff training requirements have diminished since the roll out of AMI meters, Public Service revised down the weightings for meter reading and customer accounting. This adjustment reduced cost responsibility by about $1.6 million for the Residential class with minimal impact on other classes.[20]

32. The Company maintains that, at present, purchase power agreements and market purchase costs will not have a significant impact on the POD-PH allocation and recommends excluding them from this analysis.[21]

(2) Support for POD-PH or POD Methodologies

33. Staff does not object to the POD-PH methodology but concedes that the choice of peak hours is subjective. COSSA/SEIA and Molson Coors generally agree with Public Service's POD-PH methodology. COSSA/SEIA contends the POD methodology, without peak hours, is inconsistent with the balanced purpose of the bulk power grid.[22]

---

[19] Hrng. Exh. 108 Knighten Rebuttal Testimony at 26:6-17.
[20] Hrng. Exh. 109 Klingeman Rebuttal Testimony at 20, Table DSK-R-5.
[21] Hrng. Exh. 109 Klingeman Rebuttal Testimony at 13:13–14:11.
[22] Hrng. Exh. 800 Lucas Answer Testimony at 75:8-9.

34. UCA recommends using POD without the PH adjustment, arguing that POD is intended as an hourly allocation method, so that there are no critical, or peak, hours. UCA rejects Public Service's reasons for using the POD-PH methodology, stating there is no reason to ignore any hour of the year and emphasizes, if Public Service wants to minimize rate impact, that can be better accomplished through mitigation strategies rather than the cost allocation methodology.[23]

35. WRA supports POD without PH modification, contending that POD is fair to all rate classes, considers various types of generating facilities, and provides rate stability. WRA rejects the Company's argument that the highest load hours generally drive generation investment, arguing that generating facilities provide portfolios of energy- and capacity-related value across all hours of the year. WRA finds value in the POD methodology because it allocates the costs of each resource to the hours in which it operates, then proportionately allocates those hourly costs to each class's share of load. WRA suggests Residential rate impacts can be moderated through other mechanisms, such as phasing in rate changes.[24]

36. EOC also endorses POD without the PH modification. EOC puts forth the following arguments as to why the PH modification is inappropriate: (1) utilities select resources for the full year, not just the top 1,000 hours of load; (2) the peak 1,000 hours might not align with time of use peak periods, especially as solar becomes a greater part of the Company's energy resources; (3) using POD-PH to minimize cost shifts is "goal-oriented manipulation" and is a questionable policy; and (4) hours with low marginal energy costs, such as when renewables would be curtailed, should be dealt with through rate design, not cost allocation.[25]

[23] Hrng. Exh. 300 Peterson Answer Testimony at 17:8-10.
[24] WRA SOP at 20-21.
[25] Hrng. Exh. 601 Chernick Answer Testimony at 13:14-19.

37. Like WRA, EOC suggests that rate impact mitigation can be accomplished outside of the cost allocation methodology. EOC opposes use of the 4CP-AED methodology for allocating transmission and substation costs.[26]

(3) Objections to POD-PH or POD Methodologies

38. Climax, CEC, FEA, and Walmart object to the POD-PH methodology and advocate for continued use of 4CP-AED.

39. Climax faults POD-PH as untested and flawed because it does not correctly allocate demand related costs and it does not consider cost causation because it uses a 100 percent energy allocator for all generation assets.[27] Should the Commission authorize the POD-PH, Climax recommends using 500 peak hours rather than 1,000.

40. CEC similarly offers a modification of the peak hours should the POD-PH be approved: the hours in which retail demand is at least 90 percent of peak demand, about 83 hours of the 2022 test year, with the top retail demand hours corresponding to the hours used to determine production cost in the POD-PH allocation factor calculation.[28]

41. FEA objects to the POD-PH methodology, arguing it does not sufficiently weight peak demands that drive investment in production resource capacity and does not align with critical peak hour demands impacting service reliability and conservation-related critical peak pricing objectives. FEA faults POD-PH as an energy allocation methodology, claiming it gives minimal weighting to peak hour demands that drive investment, and disputes whether it accurately reflects

[26] Hrng. Exh. 601 Chernick Answer Testimony at 17-19.
[27] Hrng. Exh. 1500 Baron Answer Testimony at 14:14-18.
[28] Hrng. Exh. 401 Higgins Cross-Answer Testimony at 6:18-23.

cost causation, creating a shift in cost responsibility across rate classes to the detriment of customers.[29]

42. Walmart objects to the POD-PH methodology, arguing that the choice of 1,000 peak hours is arbitrary and could result in rate classes with TOU components paying for peak hour costs that do not align with the TOU structure.[30] If the Commission approves a POD-PH methodology, Walmart recommends choosing a peak-hour modifier of fewer than 100 hours. Walmart argues the Company did not provide evidence that the 4CP-AED methodology is less stable than POD-PH.

b. Support for 4CP-AED Methodology

43. CEC, Climax, FEA, and Walmart support continued use of the 4CP-AED methodology. This methodology allocates costs based on contribution to four peak load hours in June, July, August, and September (4CP). The AED component is calculated by subtracting class annual Average Demand from the Excess Demand (the class 4CP). The AED is allocated to each class using the ratio of each class's Excess Demand to total retail Excess Demand.

44. CEC supports use of 4CP-AED for the allocation of production plant because it has long been used by this Commission and because it recognizes peak demand as an important part of generation investment. CEC contends 4CP-AED appropriately meets the Commission's order to identify a cost allocation methodology that is consistent across all electric generation and storage assets, concluding that wind plant can be included in the 4CP-AED with simultaneous allocation of production tax credit benefits using the 4CP-AED.[31] Should the Commission reject 4CP-AED,

[29] FEA SOP at 4.
[30] Hrng. Exh. 1000 Teague Answer Testimony at 11:16-19.
[31] CEC SOP at 9.

CEC recommends use of POD-PH with peak hours as those in which demand is at least 90 percent of system peak, which is 83 hours in the 2022 test year.

45. Climax maintains that the 4CP-AED methodology appropriately allocates fixed, demand-related capacity costs on a combination of class demands at four peaks, along with average and excess class demand for the year.[32]

46. FEA contends the 4CP-AED methodology considers both peak hour coincident demands and production capacity to serve base hourly energy demands.[33] Additionally, FEA argues that fixed costs are more accurately classified as both customer- and demand-related costs and that classifying them as only demand ignores customer impacts on the distribution costs.[34] FEA concludes, if the Commission wants to mitigate the rate impact for the Residential class, it can do so with 4CP-AED, with gradual movement toward cost of service.[35]

c. Discussion of Stratification Methodology

47. Stratification is an Equivalent Peaker Method discussed by UCA's witness Peterson, although he ultimately recommends using the POD methodology. Under Stratification, peaking units are considered pure capacity units, because of their low installed costs per kW and high fuel-related costs per kWH, relative to baseload and intermediate generating units. Costs associated with baseload and intermediate units are divided into demand and energy components, with the demand component defined in terms of an equivalent peaking unit.

[32] Hrng. Exh. 1500 Baron Answer Testimony at 18:1–16:2.
[33] Hrng. Exh. 900 Gorman Answer Testimony at 8:4-11.
[34] Hrng. Exh. 900 Gorman Answer Testimony at 10:3-7.
[35] Hrng. Exh. 900 Gorman Answer Testimony at 10:11-17.

The following example, drawn from the Regulatory Assistance Project's "Electric Cost Allocation for a New Era" shows how costs would be allocated: [36]

Generating Unit	Capital Cost $/kW	Capacity-Related Share of Cost	Energy-Related Share of Cost
Peaking unit (e.g., combustion turbine)	$ 770	100.0%	0.0%
Intermediate unit (e.g., combined cycle)	$1,020	75.4%	24.6%
Baseload unit (e.g., coal-fired)	$1,976	39.0%	61.0%

48. Despite describing Stratification in his Answer testimony, UCA witness Peterson does not recommend using Stratification in this Proceeding, stating it is a methodology for classifying demand and energy rather than an allocation method and the production costs classified to demand are allocated on a 4CP basis.[37] In his written testimony, UCA witness Peterson cites to Minnesota, South Dakota, and North Dakota as states approving the Stratification methodology for Public Service's affiliate, Northern States Power Company,[38] but during cross examination he noted that, in South Dakota, each of the four electric utilities use different allocators, including 4CP-AED and 12CP-AED.

49. Public Service contends that Stratification is an inappropriate methodology for modern resource planning for several reasons. First, that it is based on an incorrect assumption that Public Service plans its generation system based solely on using the least expensive source of generation. Public Service contends that Stratification's division of costs simply based on demand and energy is outdated and cannot be applied to a generation portfolio that includes renewable resources that provide attributes above capacity and energy. Additionally, Public Service objects

[36] Hrng. Exh. 601 Sinton Answer Testimony, Att. PC-2 at 116.

[37] Hrng. Exh. 300 Peterson Answer Testimony at 24:12-20; Dec. 15, 2023 Hrng. Trans. at 175:11-16.

[38] Although Mr. Peterson states the Commission found the Stratification methodology reasonable in Public Service's 2020 Phase II case, citing the Commission's approval of a $7.5 million downward adjustment to the Residential class's cost responsibility, the allocation methodology used in that proceeding was 4CP-AED and the Residential class adjustment was done afterward for rate mitigation purposes.

that Stratification considers peaking costs based on natural gas combustion turbines as the base for cost comparison, while the reality of today's system is that peaking resources can include a broader range of resources, including battery storage and demand response. Additionally, Public Service contends, while Stratification is based on the idea that the capacity portion of generating resources providing 100 percent firm capacity, this does not hold true for intermittent resources such as wind, solar, and battery storage.[39] The Company also notes that Stratification classifies fixed production plant into energy-related and capacity-related components, which are further allocated to classes using separate allocators for energy and for demand. Public Service concludes the record in this case does not have sufficient data to accomplish an appropriate allocation.[40]

50. CEC objects to Stratification, arguing that the classification as energy-related of all fixed generation costs greater than the cost of peaking capacity assumes that all investment in plant greater than peaking capacity is done solely to reduce energy costs. CEC contends this shifts significant costs to higher-load factor classes, violating the stability principle of regulation. Additionally, CEC maintains, if the Commission selects Stratification as the cost allocation methodology, it must also direct Public Service to reallocate its fuel costs to reflect the lower fuel costs of baseload generation.[41]

d. Summary of Allocated Revenue Requirements

51. The following tables show the allocation percentages and revenue requirement responsibilities under each methodology, based on the approved revenue requirement for Public Service in the Phase I rate case and prior to Public Service's filing of its Rebuttal case.[42]

---

[39] Hrng. Exh. 109 Klingeman Rebuttal Testimony at 27:3-15.

[40] Public Service SOP at 20.

[41] CEC SOP at 20.

[42] Tables do not add to 100 percent because "Street and Area Lighting" and "Traffic Signal Lighting" classes have been excluded. Those rate classes account for about two percent of cost responsibility.

Revenue Allocation Factor

	POD-PH[43]	POD[44]	Stratification[45]	4CP-AED[46]
Residential	44.5%	39.5%	43.4%	45.3%
Small Commercial	5.0%	4.9%	5.0%	5.0%
C&I Secondary	36.6%	38.6%	37.5%	36.6%
C&I Primary	8.3%	10.2%	8.7%	7.9%
C&I Transmission	3.6%	4.9%	3.3%	3.0%

Base Rate Revenue Requirement

	POD-PH[42]	POD[43]	Stratification[44]	4CP-AED[45]
Residential	$984,895,983	$874,338,024	$961,015,793	$1,002,232,556
Small Commercial	110,245,609	108,477,211	111,665,883	112,556,695
C&I Secondary	810,198,350	848,880,934	829,221,030	811,240,429
C&I Primary	184,674,137	225,615,118	192,834,911	174,285,586
C&I Transmission	79,284,699	107,450,084	73,864,992	67,241,682

e. Commission Findings and Conclusions

52. We recognize there is no simple answer to the choice of cost allocation methodologies, especially given the continued evolution of Public Service's system, the movement toward beneficial electrification, and concerns for rate stability across rate classes. However, considering the evidence and argument in this case, we find it appropriate to adopt for the rate design in this Phase II rate case, use of a POD-PH methodology with 1,000 peak hours.

53. We find that the POD-PH methodology as proposed by the Company is a measured step in the right direction as we adjust to an increasingly dynamic system of resource planning and cost causation. For now, on this record, POD-PH offers both a way to allocate costs based on a greater number of peak hours relative to the 4CP-AED methodology and acknowledges that peak hours are likely to migrate from only summer to some eventual higher usage times in winter with electrification. While we appreciate the arguments for using POD without a peak hour modifier,

[43] Hrng. Exh. 106 Knighten Supplemental Testimony at 11, Table JRK-S-2.
[44] Hrng. Exh. 300 Peterson Answer Testimony, Att. DEP-3.
[45] Hrng. Exh. 300 Peterson Answer Testimony, Att. DEP-12.
[46] Hrng. Exh. 300 Peterson Answer Testimony, Att. DEP-2.

we find that use of the POD-PH is a step in the right direction to reflect a focus on both a greater number of peak hours and the hours we are most concerned about in terms of cost causation, acknowledging the dynamic nature of how the system is planned and how resources are dispatched.

54. We also find merit in the Stratification methodology because it can be structured to use the detailed results from the Company's Electric Resource Plan (ERP) filings as a basis for cost allocation but note limits in this record that restrict its use at this time. Going forward, we would expect to see a broader analysis that links customer class cost allocation to drivers of cost causation as determined in the Company's most recent ERP. Specifically, we direct the Company in its next Phase II rate case, to include Stratification as a possible cost allocation methodology, using the Effective Load Carrying Capability (ELCC) data in the ERP to determine the proportion of demand-related costs for different resource types, including wind, solar, and storage. Regarding coal replacement cost assumptions, we would request that the Company explore making its analysis more consistent with the assumptions in either the Regulatory Assistance Project cost allocation report described in the Table above or with the values used by the Company in South Dakota,[47] instead of the speculative approach to coal plant replacement presented in this Proceeding.

3. Other Contested Cost Allocations

(1) Transmission and Distribution Substation Allocation

55. As explained above, Public Service proposed to continue its practice of using the same allocator for production plant for transmission and distribution substation costs. Therefore, in its Direct case, the Company proposed to use the POD-PH allocator that resulted in the spread of revenue requirements shown in the preceding table.

---

[47] *See* Hrng. Exh. 300 Peterson Answer Testimony, Att. DEP-9 at 14, Table 2.

56. In its Rebuttal case, Public Service revised its allocation methodology for transmission and distribution substations, some $355 million, from POD-PH to 4CP-AED, stating these costs are caused by coincident peak demand during the summer months, making 4CP-AED a more appropriate cost allocation methodology. Public Service notes it has traditionally used one cost allocation methodology for production plant, transmission, and distribution substation costs, but that 4CP-AED better reflects the cause-causation of transmission and distribution assets. With this modification, Public Service acknowledges that the Commission could direct the Company to use one methodology for all assets and require additional analysis in a future Phase II proceeding.[48]

57. EOC objects to use of 4CP-AED for transmission and substations, contending the costs of these assets are not necessarily driven by summer peak demand and noting the Company provides no evidence to support the change in methodology. EOC recommends the Commission direct Public Service to conduct studies before the next Phase II rate case, using AMI meter data, to develop appropriate allocators. In this proceeding, EOC recommends using a POD/POD-PH allocator for transmission costs, which EOC contends are driven by system constraints at or near generation and by the distance between generation and load, not just peak demand, and a POD-PH allocator for substation costs, which EOC notes the Company acknowledges fall between system demand and individual customer demands.[49]

58. For cost allocation of transmission and distribution substations the Commission approves the POD-PH cost allocation methodology, rejecting the Company’s proposal to use 4CP-AED. We do not find evidence in this record to support use of a cost allocation methodology

[48] Hrng. Exh. 108 Knighten Rebuttal Testimony at 25:14–26-5.

[49] EOC SOP at 24-25.

for transmission and distribution substations that is different from that used for production assets, particularly with regard to the peaking hours associated with distribution substations. We also find merit in continuing to apply one cost allocation methodology for the demand-related costs of production, transmission, and distribution substations, absent compelling evidence that another approach is more accurate.

(2) Production Tax Credit

59. Public Service agreed with CEC that production tax credit benefits associated with wind should be allocated in the same manner as production plant costs and stated it would modify its Electric Commodity Adjustment (ECA) accordingly.[50]

60. We agree that production tax credit benefits should be allocated in the ECA in the same manner as production plant costs and direct the Company to do so in its next ECA filing.

(3) Advanced Meter Costs

61. EOC questions Public Service's allocation of AMI costs as 83 percent customer-related, arguing that, because AMI benefits the system overall, only 23 percent of AMI costs should be allocated as customer-related, with the remaining 77 percent functionalized and allocated as primary distribution, generation, and transmission.[51]

62. SWEEP proposes a 50/50 AMI cost allocation between metering and distribution in order to minimize the increase in the residential Service and Facilities (S&F) charge. SWEEP observes, in the same manner as EOC, that the benefits of AMI extend beyond traditional metering and concludes that a 50/50 split is consistent with state policy goals because "lower customer charges can support equity and promote decarbonization."[52]

[50] Hrng. Exh. 108 Knighten Rebuttal Testimony at 26:6-17.
[51] EOC SOP at 14.
[52] Hrng. Exh. 1200 Brant Answer Testimony at 14:21-23.

63. Public Service responds that EOC's proposal is invalid because it is based on functionalizing a portion of Advanced Meter costs as generation and transmission, a process that is part of a Phase I revenue requirement determination.[53] Additionally, Public Service argues that the Unopposed Comprehensive Settlement Agreement (AGIS CPCN Settlement) in Proceeding No. 16A-0588E only contemplates functionalizing Advanced Meter costs within the distribution system.[54] Public Service rejects SWEEPs proposal as well because it is not based on data or evidence in this Proceeding. Public Service states any discussion of revisiting the functionalization of AMI costs is premature until the full AMI rollout is complete, and the full costs are known.

64. The Commission finds that the record in the Proceeding on this issue is inadequate to order changes to the allocation of AMI costs but also finds that there are system-wide benefits of AMI that should be better reflected in the allocation. Therefore, the Commission directs the Company to maintain allocation of AMI costs as 83 percent customer-related for this Proceeding but directs the Company to provide a more robust analysis of these costs and identification of the scale and proper allocation of benefits associated with AMI when it files its next Phase II rate case.

[53] The record in this Phase II rate case calls into question Public Service's assertion that the "functionalization of costs" is a process exclusive to a Phase I rate case. The impacts of the cost allocators used in a CCOSS strongly relate to the functionalization and categorization of costs and are likely expected to be legitimate factors for review by the parties and the Commission in a Phase II rate case. Moreover, because one of the principal outputs of a Phase I rate case is generally understood to be an overall measure of the Company's revenue requirement for collections through base rates, it is possible that potential intervenors would not recognize that a Phase I rate case is where disputes over cost functionalization and categorization would be addressed and fixed for later application in a Phase II proceeding. It is further reasonable to anticipate potential deficiencies in case records if cost functionalization and categorization is kept separate from CCOSS considerations, rate design, and the mitigation of bill impacts across customer classes.

[54] Public Service SOP at 22.

(4) Service Laterals

65. EOC recommends requiring Public Service to modify its service lateral allocation to account for the diversity of load for multifamily buildings. EOC contends this modification could reduce service lateral costs to the Residential class by 15 percent, or some $3.7 million.[55]

66. Public Service agrees that a service lateral allocation should be more thoroughly analyzed in its next Phase II rate case, but rejects a cost allocation in this Proceeding, arguing that EOC's proposal does not have quantitative support and that EOC does not show that making the adjustment results in just and reasonable rates.[56]

67. The Commission agrees that there is insufficient evidence in this record to make the modification to the service lateral costs recommended by EOC and thus rejects EOC's recommendation. However, we direct Public Service to provide sufficient analysis in the next Phase II rate case so that we can more fully review the costs of service laterals to multifamily buildings and make any appropriate adjustments in that case to cost allocation.

4. Residential Customer Charge (Monthly S&F Charge)

68. Although Public Service had initially proposed an increase in Residential S&F charges from $6.29 to $8.00 per month, inclusive of the Electric Affordability Program (EAP) charge, with the changes made to the CCOSS in its Rebuttal case the Company proposes an S&F charge of $7.90.

69. EOC recommends rejecting the proposed increase and suggests that an increase to $7.10 would be more appropriate. SWEEP also rejects the proposed S&F increase, offering that $6.90 would be more appropriate. Both SWEEP and EOC argue that the increase to $7.90 stems

---

[55] EOC SOP at 26.

[56] Public Service SOP at 23.

from inappropriately allocating some 83 percent of AMI costs as customer related. Both intervenors express concern for income qualified customers.

70. Public Service maintains the S&F charge proposals from both EOC and SWEEP are not cost-based and suggests that energy affordability is more appropriately addressed by the Energy Insecurity Working Group created as a result of Decision No. C23-0592 in Proceeding No. 22AL-0530E.

71. We find good cause to set the Residential S&F charge at $7.10. The Commission is concerned with the increasing S&F charge from its current level, but as Public Service points out, the proposed S&F charge is based in costs, and the increase represents the necessary gradualism in adjusting rates accordingly. We are further confident that, going forward, the Energy Insecurity Working Group will provide workable proposals for assisting income qualified customers.

5. Medical Exemption Program (MEP) Rates

72. Staff contends that Public Service's proposed MEP rates in this Proceeding are moot because the Commission authorized new rates on September 1, 2023, in Proceeding No. 23AL-0393E.

73. Public Service counters that Proceeding No. 23AL-0393E authorized a new methodology for calculating MEP rates, moving from a calculation of MEP energy rates equal to the annual average energy rate for Schedules R and RE-TOU to setting the MEP rate equal to the off-peak energy rate for Schedule RE-TOU. The new methodology was approved after Public Service filed its Direct case in this Proceeding, so the Company used the new methodology to calculate MEP rates when it filed its Rebuttal case and asserts these are the rates that should be approved in this Proceeding.

74. The Commission approves the MEP rates as proposed by the Company consistent with the CCOSS set forth in the Company's Rebuttal case and any modification made by the Commission to the CCOSS in this Decision.

6. Time of Use Periods (RE-TOU and C-TOU)

(1) Public Service Proposal

75. In Proceeding No. 19AL-0687E, the settling parties agreed that time of use (TOU) periods will remain unchanged until Public Service files an advice letter on April 1, 2025. Based on this, Public Service proposes no change to the TOU periods in this Proceeding; Staff, COSSA/SEIA, EOC, and SWEEP agree. WRA agrees to leaving the periods unchanged but in its closing Statement of Position encourages the Commission to move up the date for review of the TOU periods.

76. As ordered in this Proceeding, Public Service provided Supplemental Direct testimony showing load net of renewables for each year from 2024 through 2030, looking at the top 100 hours for each of the years, concluding that shifting on-peak pricing periods to later in the day would be appropriate in the future. Additionally, Public Service determined that winter morning hours could become important with increased electrification, noting the possibility of an on-peak period of 5:00 a.m. to 8:00 a.m. The Company proposes a year 2030 timeframe for re-visiting TOU periods because all resources identified in the Clean Energy Plan portfolio of the Company's 2021 ERP and Clean Energy Plan should be in place by then.

77. Public Service objects to changing the TOU periods now because doing so would require a modified customer educational program, which the Company claims could lead to customer confusion and dissatisfaction.[57] The Company offers that the opt-out rate has been only

[57] Hrng. Exh. 104 Knighten Supplemental Direct Testimony at 8:16–11:10.

1.1 percent and that customers are modifying their behaviors and cautions against changes that could alter this. Additionally, Public Service argues that adding a new TOU period would require additional analysis.[58]

(2) Intervenors' Positions

78. Staff recommends the Commission approve Public Service's proposal to maintain the existing TOU periods for all rate schedules until a comprehensive re-evaluation in 2025. Staff argues the Company's existing RE-TOU periods comply with prior Commission decisions with the aim to minimize changes to RE-TOU while customers move to the new rate "to avoid disruption of the transition process and ratepayers' adaptation to the new TOU rates."[59] Staff explains, while the prior settlement principally prohibits the Company from filing an advice letter to change the RE-TOU rate before April 1, 2025, the settlement did not prohibit intervening parties in this Proceeding who joined that settlement from advocating for a change to TOU periods before the 2025 Advice Letter is filed. Staff further argues that, while Public Service's forecasts suggest loads may shift in the future, the Commission should not be overly hasty to change TOU hours while advanced meters are still being rolled out and the transition to RE-TOU is incomplete. Staff warns a premature change to RE-TOU in this Proceeding will complicate Company messaging, confuse customers, and muddle the price signals. According to Staff, implementing a change before the TOU rollout has concluded will also fundamentally alter the structure and intent of previous Commission decisions.

79. Although WRA does not support changing TOU periods in this Proceeding,[60] it encourages beginning customer education about the changes now so that customers will be

[58] Public Service SOP at 9.
[59] Staff SOP at 5 (citing Decision No. R20-0642 at ¶ 163).
[60] WRA SOP at 9.

prepared when the time periods do change. WRA recommends reviewing all TOU rate schedules (Residential, Commercial, and Secondary General) in an Advice Letter filing that could be made in Fall 2024 rather than April 2025, with a mandatory stakeholder meeting held several months prior. WRA suggests the stakeholder meeting could be held as a Commission technical conference. Prior to that meeting, WRA suggests Public Service be required to provide stakeholders the following information:[61]

- Updated TOU data, including generation assumptions that reflect an updated ERP
- Load forecasts that include hearing electrification
- Distribution and hourly total MWh of top 1,000 load net of renewables hours
- Hourly average date by month, including load net of renewables, load, average CO_2 emissions intensity, and hourly renewable energy curtailment

80. WRA further recommends the Commission direct the Company's future TOU evaluations to focus on 2031, the year after the Comanche 3 coal-fired power plant in Pueblo, Colorado, is retired.

81. COSSA/SEIA encourages the Commission to refrain from making changes to the TOU periods until the April 2025 Advice Letter filing so that customers can receive sufficient education as to how the pricing structure works. COSSA/SEIA contends the current structure was developed carefully to provide price signals that customers can understand, providing certainty and the ability to adjust behavior, and argues that any changes in TOU periods require sufficient data for support. COSSA/SEIA suggests the current structure is achieving its goals of modifying customer behavior and acceptance, which could be disrupted if the periods are modified.[62]

82. Boulder supports beginning the TOU review in the summer of 2024.

[61] WRA SOP at 12-13.

[62] COSSA/SEIA SOP at 25-26.

(3) Commission Findings and Conclusions

83. The settlement and supporting testimony in Proceeding No. 19AL-0687E describe the April 1, 2025 date for the TOU Advice Letter filing as coinciding with the date upon which all Residential customers will transition from Schedule R to RE-TOU. (The schedule for Advanced Meter roll-out runs through the end of 2024.) Therefore, it appears the intent of the April 1, 2025 filing date was to allow all customers to be on the RE-TOU rate schedule for a period of several months before any changes are made to the rates or TOU periods. Acknowledging that this date was set five years forward from the date of the settlement agreement, the settling parties allowed for modification of rates prior to 2025 if there was increase, defined as 22 of the top 100 hours, in load net of renewable hours between 7:00 p.m. and 9:00 p.m.

84. We find it necessary to move up the target date for Public Service's required TOU Advice Letter filing so that the Commission can consider and implement changes to the TOU periods prior to the start of the 2025 summer cooling season. The underlying drivers of costs in Colorado are increasingly being driven by factors other than a handful of peak summer hours, as evidenced by our recent approval of significant new generation and transmission investment in the Company's ERP in Proceeding No. 21A-0141E. As a result, we find the current time periods are not well matched with the evolving cost drivers. Therefore, by this Decision, we order Public Service to file an advice letter that will allow new RE-TOU and C-TOU rate schedules[63] to be in effect by May 1, 2025. To meet this target, we expect the Company to file its advice letter by or before September 3, 2024.[64] The desired May 1 effective date is selected so that there is at least a one-month period for the Company to communicate with customers and for customers to

[63] As explained below, this filing will also include a SG-TOU pilot.

[64] We note that this schedule allows 210 days for the Commission to render a decision on the Company's advice letter.

familiarize themselves with the new peak periods and adjust their behavior, prior to the ramping up of the cooling season. We direct the Company to use the best available cost causation data – including forward-looking projections from the ERP process that include additional solar and storage – to develop the rate periods for this filing. Based on the record in this Proceeding, we would expect the peak period to shift later, closer to 6:00 p.m. to 9:00 p.m. weekdays for both TOU rates and demand charges, with the potential for shoulder periods on either side, as driven by the data.

85. We further direct Public Service to provide stakeholders the information suggested by WRA and to meet with stakeholders prior to filing this advice letter. Although we recognize the concerns raised by Public Service and the intervenors as to customer education and acceptance of the TOU schedule, given the acceptance rate to date and our belief in the flexibility of customers, we do not see great adverse effects in making changes to rates and TOU periods beginning with the 2025 cooling season. Additionally, continuing to train customers on time periods that we already understand to be out of date may be of limited value. We find it necessary to strike a balance between some level of consistency and some measured approach to adjust these periods so that pricing is not sending the wrong signal at the wrong time of day. Contrary to the objective of these rates, there is the potential of simultaneously curtailing large amounts of renewables mid-afternoon while rates are higher and discouraging demand, and then see the need for additional generation to meeting growing demand in the late evening. Indeed, it is the nature of TOU rates that changes to time periods and rates will be necessary over time to continue to send price signals to reduce the overall costs of the system, so customers will need to become accustomed to periodic modifications. To this end, we also direct Public Service to begin customer education as to the changes in rates and time periods no later than October 2024. We recognize this initial customer

education will necessarily be a nuanced message that alerts and educates customers to the need for constant adjustment of peak hours, based on the evolving system. Once the new rates and periods are established, the Company will be in position to alert customers to the specific changes so that customers can adjust their behavior prior to the cooling season.

7. Schedule C and Schedule C-TOU 50 kW Demand Threshold

(1) Public Service Proposal

86. Public Service proposes to maintain the 50 kW threshold for moving Schedule C-TOU and Schedule C customers to Schedule SG, as was established in the 2020 Phase II rate case. This threshold is the point at which a customer is not eligible to receive service under Schedules C-TOU or Schedule C and must take service under Schedule SG, which has a demand charge. However, there is no automatic switching of customers to Schedule C-TOU if use drops below the 50 kW threshold.

87. In response to a Commission directive in the 2020 Phase II case,[65] Public Service sent 14,000 email notifications to Schedule SG customers that were under the 50 kW threshold indicating they could potentially benefit from switching rate schedules, but some 17,500 customers eligible for the C-rate class remain on Schedule SG, despite the communication. The Company contends that proactively moving customers to the rate schedule that results in the lowest bill would mean a significant revenue reduction for the Company.[66] Public Service also cites to tariff language that places the responsibility of rate selection on the customer:

> Where there are two (2) or more rate schedules applicable to any class of service Company will, upon request of applicant, explain the conditions, character of installation or use of service governing the several rate schedules and assist in the selection of the rate schedule

---

[65] Decision No. C21-0536 in Proceeding No. 20AL-0432E.

[66] Hrng. Exh. 103 Wishart Direct Testimony at 31:17-20.

> most suitable for applicant's requirements. Applicant, however, shall be responsible for the final section of said rate schedule, and Company assumes no liability therefore.[67]

88. Public Service states the commercial rate tool it was directed to develop in the 2020 Phase II rate case will be available in the first half of 2024.[68]

(2) Intervenors' Positions

89. Boulder recommends the Commission direct Public Service to proactively provide a customized bill and voluntary product suite comparison to all customers currently taking service under Schedule SG but that are eligible to take service under Schedule C-TOU or Schedule C. Additionally, Boulder suggests transitioning to Schedule C all eligible customers currently taking service under Schedule SG who would see annual bill savings of 25 percent.

90. Boulder raises concern the rate analysis tool Public Service was to make available in 2022 will now not be deployed until 2024. Boulder further points out, as an example, that in Texas the automatic annual rate review switches customers between energy-only and demand rates based on average annual peak demand.[69] Boulder argues that Public Service has not provided evidence that customers who shift from Schedule C to Schedule SG alter their load shape, undermining the Company's contention that automatically moving customers from Schedule C to Schedule SG benefits the system through behavioral changes.[70]

91. Boulder also argues the proposed S&F charge in this Proceeding, $70.28 from $41.13 per month, will result in a higher annual charge just for S&F under Schedule SG than the annual bill under Schedule C. Boulder notes the demand for these customers is similar to that of

[67] Public Service P.U.C. No. 8 - Electric, Sheet No. R11.
[68] Hrng. Exh. 108 Knighten Rebuttal Testimony at 48:20-21.
[69] Boulder SOP at 6.
[70] Boulder SOP at 7.

residential customers, underscoring the argument that these customers are not imposing costs on the system that justify the increased S&F charge.

92. In its Rebuttal case, Public Service counters that moving customers from Schedule SG to Schedule C-TOU would allow customers to realize bill savings without behavioral changes and that the 25 percent threshold proposed by Boulder is arbitrary and without quantitative support.

(3) Commission Findings and Conclusions

93. The Commission confirms that the demand threshold for Schedule SG shall be maintained at 50 kW. However, we are concerned that many of the customers who take service under Schedule SG should, instead, reasonably take service under Schedule C or C-TOU and would benefit significantly financially by doing so. Sixty percent of customers taking service under the SG rate class do not have peaks over 50 kW,[71] meaning they are eligible for the Schedule C and C-TOU rates. This represents a concerning number of customers on a rate that is not designed for the size of their demand and could lead to significantly skewed results in actually trying to understand cost causation in the CCOSS. This is especially true for customers newly occupying commercial spaces who are put on Schedule SG by default, even if prior use on the meter of that facility would not substantiate those customers being on the SG rate and no evidence that the new customer will reasonably be expected to experience a demand higher than 50 kW. To address this, we direct the Company to immediately transition to the use of 12 months of the previous occupant's usage records to determine the appropriate rate schedule for new commercial customers, as the default circumstance.

94. Additionally, based on testimony filed in this Proceeding, we direct Public Service, in its next Phase II rate case filing, to include a version of its CCOSS that demonstrates the revenue

[71] Hrng. Exh. 103 Wishart Direct Testimony at 33, Table SWW-D-5.

requirement of Schedule SG excluding customers whose demand is less than 50 kW, instead including those customers in the C/C-TOU rate class or other, as appropriate, and to propose a new rate class for customers with demand between 50 and 100 kW, with a TOU component, and any proposed recovery through a demand component of less than 40 percent of the total projected recovery. The dramatic difference between the C/C-TOU rates, which are energy-only, and SG rates, which collect around 80 percent of the revenue by the demand component, leads to a massive difference in billing for the same customer with no change in usage, just depending on what tariff they are taking service under. Recognizing that the smallest customers properly taking service on the SG rate may have just as much or more in common with Schedule C customers than some of the very large customers driving cost causation in Schedule SG, it is reasonable to consider a moderation of approach to investigate an intermediate size with a more measured demand-component. In the Company's last Phase II rate case, the Recommended Decision required that, in its next Phase II rate case, the Company conduct a thorough analysis in its CCOSS of the impact of increasing monthly demand threshold in Schedule C to 50 kW, as well as whether the monthly demand threshold in C-TOU should be increased to 75 or 100 kW in the future. The Commission expanded on the Recommended Decision in its ruling on exceptions to direct an examination also of whether a lower demand threshold, such as 25kW can be a barrier to building electrification. While this analysis could have been helpful in determining a path forward considering a wider range of options, no such in-depth analysis was found in the record, so the Commission has elected to take action on this point to require the above exploration of treatment of customers with intermediate sized loads. It would also be beneficial for the Company to track any changes in usage among customers who migrate from the C/C-TOU to SG or vice versa to determine if there is any actual behavioral change associated with their transition to or from the demand-rate.

95. The Commission is also concerned that Public Service has not fully complied with the requirements of the directive in the 2020 Phase II rate case regarding customer notice as to the option to take service under Schedule C or C-TOU and the deployment of a rate comparison tool, which the Commission anticipated would be accomplished by the end of 2022 based on information previously provided by the Company. We therefore direct Public Service to make its commercial rate comparison tool available to customers by March 31, 2024, and have a process in place through with customers will be able to speak directly to a single point of contact to clarify their rate schedule and make any appropriate changes. When the rate comparison tool and process are available, the Company shall file a notice to the Commission in this Proceeding.

96. The Company shall also contact all customers on Schedule SG who would be eligible to take service under Schedule C or C-TOU within 30 days of the availability of the rate comparison tool to notify them that moving to a different rate schedule could be beneficial and to provide them with a link and information regarding how to access the rate comparison tool, as well as a customer service phone number at which the switch to a new tariff could be completed in one interaction. The Company shall again file a notice in this Proceeding when that communication has been completed and shall include the number of customers contacted and a copy of the communication sent to them.

8. Secondary General (Schedules SG & SG-CPP) Time Differentiated G&T Charge

(1) Public Service Proposal

97. In its Statement of Position, Public Service explains that Schedule SG is the Company's largest rate schedule by sales volume. Its monthly customer charge (*i.e.*, the Service and Facilities Charge (or S&F charge)) collects approximately 6 percent of total Schedule SG revenue. The distribution demand charge accounts for approximately 38 percent of total, while a seasonally differentiated generation and transmission (G&T) demand charge accounts for approximately 44 percent of revenue. The rate's energy charge collects approximately 12 percent of Schedule SG revenue.

98. In order to encourage Schedule SG customers to shift usage out of peak hours and to flatten their load patterns, Public Service proposes modifying Schedule SG and Schedule SG-CPP to include time-differentiated G&T demand charges. Public Service initially requested that the period for time-differentiated demand charges be set as 2:00 p.m. to 7:00 p.m. on non-holiday weekdays but modified this in its Rebuttal case to 3:00 p.m. to 7:00 p.m. on non-holiday weekdays. Under this proposal, customers who receive an Advanced Meter by December 31, 2024, will transition to the time-differentiated demand charge beginning on April 1, 2025, while those receiving Advanced Meters after January 1, 2025, will be transitioned on April 1 of the year following the installation of their Advanced Meter.

(2) Intervenors' Positions

99. COSSA/SEIA recommends modifying the Schedule SG rate design to shift much of the allocated revenue requirement from demand charges to energy charges in order to send price signals[72] and making the Company's pilot SG-TOU rate a permanent service offering.

[72] Hrng. Exh. 800 Lucas Answer Testimony at 44:4–46:7.

100. Public Service opposes COSSA/SEIA's recommendation to move Schedule SG into an energy-based rate because there are no results from the Schedule SG-TOU pilot that support an energy-based rate. Public Service further argues that COSSA/SEIA's proposal would move $130 million from time-differentiated G&T demand charge into a non-time differentiated energy charge and $30 million of costs from the distribution demand charge into a non-time differentiated energy charge and should be rejected.[73]

101. Kroger recommends rejecting the time-differentiated demand rates and revisiting them in the next rate case or requiring the Company to modify the periods to be consistent with the Company's projected load net of renewables for 2025, which indicate highest peak load between 7:00 p.m. and 9:00 p.m.[74]

102. Public Service disagrees with Kroger's proposal that the time-differentiated demand charges not be implemented until all Advanced Meters are deployed. The Company also rejects Kroger's alternative proposal as it would undermine the goal of sending price signals to Schedule SG customers.[75]

(3) Commission Findings and Conclusions

103. We support Public Service in modifying Schedules SG and SG-CPP to move to a time-differentiated demand component, but we further direct the Company to include the proposed time-differentiated demand charge for Schedules SG and SG-CPP in the advice letter we have directed to be filed by September 3, 2024, for an effective date of May 1, 2025, consistent with the discussion above addressing the RE-TOU and C-TOU rates. We expect the Company to use the

[73] Public Service SOP at 26.
[74] Kroger SOP at 5.
[75] Hrng. Exh. 108 Knighten Rebuttal Testimony at 56:12-18.

most appropriate load data available when determining the hours for the time-differentiated demand charge.

9. Secondary General Low-Load Factor (Schedule SGL)

104. Schedule SGL, with some 500 customers, is available to customers with load factors of 11 percent or less. COSSA/SEIA recommends increasing the breakeven monthly load factor to 30 percent to attract customers who do not qualify for Schedules SG-TOU or SG-CPP.

105. Public Service and Kroger both oppose this proposal. Kroger faults COSSA/SEIA for failing to provide evidence that the proposal aligns with cost causation or will send effective price signals. Kroger also notes the Schedule C-TOU option is available to customers on Schedule SG, providing a rate option with energy-based charges. Kroger suggests these changes should be considered in the next Phase II rate case, where Public Service could provide a cost allocation base on a separate rate class.[76]

106. Public Service states that 60 percent of Schedule SG customer have access to Schedules C and C-TOU and that those rates are beneficial for customers with load factors less than 45.5 percent, thus COSSA/SEIA's proposal is unnecessary. The Company also contends that COSSA/SEIA's proposal would result in unwarranted bill reductions for existing Schedule SGL customers, because there would be a 59 percent reduction to energy charges, and that the rates would not recover the authorized revenue requirement.[77]

107. We will not adopt COSSA/SEIA's proposal. The Company has demonstrated there are sufficient alternative for customers with load factors of 30 percent or less.

---

[76] Kroger SOP at 18.

[77] Public Service SOP at 36.

10. Production and Load Meter Charges

108. COSSA/SEIA suggests that the costs of AMI production meters for systems under 10 kW should be recovered from all customers because the Company utilizes the AMI production meters at for general solar forecasting purposes, so the meters benefit the entire system. COSSA/SEIA also recommends the Commission deny the Company's proposal to replace all non-AMI production meters with AMI production meters.

109. Public Service responds that there is no proposal to replace non-AMI production meters, although some replacements have been made in order to continue billing some Solar*Rewards customers. The Company also contends that because of contractual obligations to Solar*Regards customers, it cannot unilaterally uninstall existing production meters.[78]

110. We deny COSSA/SEIA's request to spread the cost of AMI production meters across rate base. We find the record is not developed sufficiently on this issue to determine the impact on the S&F charge nor to determine if the resulting rates would be just and reasonable. However, based on this Phase II rate case record, we question the Company's decision-making that has led to continued expenditures on production meter costs for small systems without proper examination of need and benefits of such meters, and therefore we expect this will be a prudency issue carefully reviewed in Public Service's next Phase I rate case, as it is our understanding that the majority of production meter replacements may have occurred after the test year utilized in this Proceeding. Similar to the issues in this Proceeding surrounding the allocation of advanced meter costs, the treatment of production meter costs may be another reason for the Company to file a combined Phase I and Phase II case for its next rate case.

[78] Public Service SOP at 40.

11. Secondary Photovoltaic TOU (Schedule SPVTOU)

111. Schedule SPVTOU is intended to make solar net metering more financially viable for C&I Secondary customers and currently is limited to customers with service loads between 25 and 500 kW, with a photovoltaic system of at least 10 kW, and who participate in Solar*Rewards. A fourth requirement is a 15 MW annual installation cap for new photovoltaic installations.

112. In response to COSSA/SEIA, Public Service agreed to remove the Solar*Rewards participation requirement and is proposing to modify the service load requirement to 25 to 1,000 kW (rather than 500 kW) and lower the PV system capacity to 8 kW. The Company contends these modifications address COSSA/SEIA's concerns regarding customer use of renewable energy credits and the programs availability to a wider range of customers, within the bounds of the settlement reached in Proceeding No. 21A-0625EG.

113. We find good cause to approve the modifications made to Schedule SPVTOU.

12. Electric Heating Rate Pilot

114. SWEEP proposes the development of an Electric Heating Rate Pilot, available to residential customers with existing electric heating and an AMI meter, with a focus on income-qualified customers and customers in disproportionately impacted communities. SWEEP suggests that a stakeholder group would develop the rate design, as well as monitoring and reporting metrics. The pilot would be filed by June 1, 2024, and run for at least four heating seasons.

115. WRA supports SWEEP's proposed Electric Heating Rate Pilot, suggesting the formation of a stakeholder group to collaboratively design a pilot and that Public Service be directed to file a proposal for an Electric Heating Rate Pilot within six months of a Commission decision in this Proceeding.

116. Staff and Public Service object to the Residential Heating Rate Pilot as premature, noting it is not clear that such rate is necessary to encourage electric heating nor that a rate design solution would be fair, because it would be paid for by other customers. Public Service also objects to the timeline proposed by SWEEP as unduly aggressive.[79]

117. We will deny the proposed Electric Heating Rate Pilot as premature but suggest that such a pilot could be warranted in the coming years as Colorado increasingly moves toward beneficial electrification. Although we do not approve this proposal, we do commend SWEEP for its creative thinking on this issue and for bringing this forward for our consideration. One issue for further consideration is whether this could be pursued as a voluntary high-differential time-of-use rate that could send a much more aggressive voluntary price signal to move load off the peak period. This could be a viable option for customers who are willing and able to move load off of that peak time, which is likely to include many customers with beneficial electrification, but by not being exclusive to them could address issues of verification and fairness that may be difficult to tackle.

13. Outreach to Income-Qualified Customers

118. EOC witness Nussbaumer presented data and analysis describing the number of income-qualified customers in Public Service's service territory, the characteristics of income-qualified households' electricity use, rate affordability, energy burden, and appropriate TOU period. Notably, he shows that the number of energy burdened households is much larger than Public Service estimates.[80]

[79] Public Service SOP at 39.

[80] Hrng. Exh. 602 Nussbaumer Answer Testimony at 6:5–10:14.

119. EOC witness Bennett further explains that income-qualified customers face high energy burdens such that they face unwelcome choices between paying certain bills and foregoing other life-necessities.[81] He also concludes that there is a significantly underserved population of energy-burdened customers and that the disparity between those in need and those who are provided energy assistance exists for a number of reasons, including but not limited to limits on funding, eligibility requirements, and barriers in enrollment.[82]

120. Accordingly, we look for solutions to address the gap between the needs of income-qualified customers and the resources available to help them, including improved identification of customers most at risk of permanent disconnection and finding ways, through propensity-to-pay or other customer-specific data, of identifying these customers earlier in the process especially before they are multiple months in arrears.

14. Uncontested Requests

121. The Commission enters findings approving the following items that Public Service describes as uncontested:

(1) 2022 Test Year Data

122. The Commission finds Public Service's use of the 2022 data and the associated revisions to the POD-PH allocator are reasonable.

(2) IVVO Lost Revenue

123. The Commission finds that by using the 2022 Test Year data, it is not necessary to continue IVVO-related lost revenue recovery through the Public Service's Electric Commodity Adjustment.

[81] Hrng. Exh. 600 Bennett Answer Testimony at 11:15–12:3.
[82] Hrng. Exh. 600 Bennett Answer Testimony at 14:5–10.

(3) Meter Weighting Factors

124. The Commission finds Public Service's revisions to the meter weighting factors used in the CCOSS as set forth in its Rebuttal case are reasonable.

(4) Re-Functionalization of Distribution Costs

125. The Commission finds the re-functionalization of certain distribution costs from secondary to primary in the CCOSS is reasonable.

(5) EVRAZ Treatment

126. The Commission finds that Public Service correctly accounted for EVRAZ in the CCOSS in accordance with Decision No. C18-0889 in Proceeding No. 18A-0569E.

(6) Schedule P-EV / P-EV-CPP

127. The Commission approves Public Service's proposed Schedules P-EV and P-EV-CPP.

(7) Schedule PG-CPP G&T Window

128. Consistent with our finding for the Schedule SG, we approve the Schedule PG-CPP time-differentiated demand charges be based on demand measured between 3:00 p.m. and 7:00 p.m. on non-holiday weekdays to align with the Company's other C&I Primary time-differentiated demand calculations.

(8) Schedule SPVTOU-B G&T Window

129. Likewise, we approve the Schedule SPVTOU Section B time-differentiated demand charges be based on demand measured between 3:00 p.m. and 7:00 p.m. on non-holiday weekdays to align with Public Service's other C&I Secondary time-differentiated demand calculations.

II. ORDER

A. The Commission Orders That:

1. The tariff sheets filed by Public Service Company of Colorado (Public Service) on May 15, 2023, with Advice Letter No. 1923-Electric are permanently suspended and shall not be further amended.

2. Public Service shall file an advice letter compliance filing to modify the tariff sheets in its Colorado P.U.C. No. 8 - Electric Tariff consistent with the findings, conclusions, and directives in this Decision. Public Service shall file the compliance tariff sheets in a separate proceeding and on not less than 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.

3. 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.

4. This Decision is effective on its Mailed Date.

B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING February 7, 2024.

(S E A L)

ATTEST: A TRUE COPY

Rebecca E. White,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK

____

MEGAN M. GILMAN

____

TOM PLANT

____

Commissioners