

IN THE MATTER OF THE)
TRANSMISSION OWNER FILING) DECISION & ORDER 25-7 (TO)
OF COLORADO SPRINGS UTILITIES)

- 1

5. Utilities' Annual Transmission Revenue Requirement ("ATRR") in the current OATT was last updated and approved in 2017 by the City Council with rates phased in effective on January 1 of 2017, 2018 and 2019. The ATRR was calculated and supported through a Cost-of-Service Study and established rates for both Firm and Non-Firm Point-to-Point Transmission Service. In preparation for the transition into the SPP RTO, Utilities is submitting this TO filing to inform City Council how wholesale transmission rates, terms and conditions will be managed and established as of the date that Utilities joins the SPP RTO. The primary objectives of these proposed modifications are to:
 - a) Establish a Transmission Formula Rate ("TFR") template and protocols, anticipated to be submitted to SPP as part of their filing with FERC and updated annually after approved membership in SPP in accordance with the associated TFR implementation protocols.
 - b) Utilize the TFR methodology to establish the initial updated ATRR and associated rates for Network Integration Transmission Service ("NITS") and for Firm and Non-Firm Point-to- Point Transmission Service using the projected cost of service to ensure adequate revenue recovery in 2026 and in which revenue requirement and charges will be updated annually thereafter while a member of the SPP RTO in accordance with the associated TFR implementation protocols.
6. Utilities proposed changes and actions as follows:
 - a) **Transmission Formula Rate Template and Implementation Protocols**
 - i. Given the upcoming transition to SPP membership, Utilities is taking proactive steps with this filing to establish a TFR. TFR methodologies are approved by FERC and, upon approval, allow utilities to input historical and projected data to calculate the cost of service and subsequent rates on an annual basis. The formula defines the methodology and various inputs for determining the utility's cost of service. These inputs include, but are not limited to, the rate base (Electric Plant in-service plus adjustments), depreciation and amortization expenses, operation and maintenance expenses, administrative and general expenses, rates for taxes other than income tax (such as Surplus Payments to the City and Franchise Fees) and an allowance for allocated debt service coverage. All inputs and data must be supported by additional information adequately describing how the inputs are derived. As Utilities is not required and therefore does not compile and file a FERC Form 1 report, many of the key inputs to the TFR for calculating the projected ATRR or reflecting the historical costs to be used for True-Up calculations are summarized through various workpapers compiled from internal software systems and records. The formula rate takes these data inputs for a rate year and applies historical revenues collected in that year resulting in an under-collection or over-collection. This true-up mechanism derives a value that, in addition to any necessary

prior period adjustments, including applicable interest, is then added to forecasted or projected expenses less any revenue credits to arrive at a Net Revenue Requirement for the projected rate year.

- ii. Utilities 2026 ATRR has been prepared utilizing its TFR which incorporates the cash basis approach (cash flow) of the prior cost of service methodology. Utilities is an enterprise of the City of Colorado Springs, and as a governmental entity, is tax exempt. As such, Cost of Service has historically utilized this cash-needs basis for setting rates and therefore does not calculate a return on the rate base. Annually, City Council approves Utilities' budget. Utilities proposes to use budgeted projected values to populate the TFR for each calendar year in order to calculate the annually updated ATRR. Utilities anticipates that these rates will go into effect on the effective date of the transfer of functional control of Utilities transmission facilities to SPP. Assuming the necessary regulatory approvals are issued, Utilities anticipates an effective date of April 1, 2026. As such, the initial rate period for calculating a proposed formula rate is calendar year 2026, but the initial rates will be in effect for a partial year from the effective date of Utilities transfer of functional control of its transmission facilities to SPP through December 31, 2026.
- iii. The methodology for calculating Utilities proposed formula rate is largely aligned with the original methodology used in the currently effective ATRR by utilizing the same transmission-related cost components and incorporates similar allocator bases for those functionalized cost components. The TFR comprises three main components. The first is a statement of the ATRR for NITS that will be included in the Revenue Requirement and Rates ("RRR") file as defined in the SPP Tariff as well as the underlying rates for Schedule 7 Long-Term Firm and Short-Term Firm Point-to-Point Transmission Service, and for Schedule 8 Non-Firm Point-to-Point Transmission Service. The second component is the formula itself with the unpopulated tables that will be included in Attachment H of the SPP Tariff. Finally, Utilities' Protocols describe how Utilities will implement and update its transmission rates each year, what the review procedures will be, how customer challenges will be resolved, and how any changes to the annual rate updates will be implemented. These Utilities' Protocols will be included in the SPP Tariff Attachment H. When the proposed rate becomes effective, SPP will post the populated TFR, including the worksheets and Utilities' Protocols, on its website. Utilities may also provide appropriate links to the SPP Tariff on Utilities' website.

- b) **Transmission Formula Rate Template Calculation of the Projected ATRR –** All Tables included in the TFR Template that are referenced herein can be found in Utilities 2026 Rate Case filing. Table P1 outlines the calculation for Utilities Projected ATRR while Table T1 outlines the calculation of a historical ATRR based on actuals which would be used, alongside actual revenues for calculating the over-

collection or under-collection to be added to the projected ATRR. Table P1 (Projected ATRR) and Table T1 (ATRR) have the same layout in the template, and line references for expenses in Table T1 (ATRR) correspond to those in Table P1 (Projected ATRR) for reference to projected expenses. The major sections of the calculations are Operating Expenses (Line 14), Capital Projects Expense (Line 29), and Other Taxes (Line 42). These items, in addition to an allowance for allocated debt service coverage (Line 47) comprise the total gross ATRR (Line 48). Any Revenue credits (Line 49) are identified and offset the ATRR for a total net ATRR (Line 50) that is carried over to Table TRC, Line 1 as the Projected ATRR.

i. Total Operating Expenses include:

1. Transmission Operating and Maintenance (“O&M”) Expense (Table T1, Line 1) is reflected in Table E1, with actuals incurred in 2024 as well as projected to be incurred in calendar year 2026, and listed by transmission account, consistent with the FERC Uniform System of Accounts. The amount of Transmission O&M incurred for this period is approximately \$5.9M. Utilities TFR Template excludes Account 561 Load Dispatch expenses and Account 565 Transmission by Others (if any).
2. Administrative and General (“A&G”) Expense (Table T1, Line 11) is reflected in Table E2 consistent with the FERC Uniform System of Accounts with actuals incurred in 2024 and projected A&G expenses to be incurred in calendar year 2026. With Utilities being a four-service utility, total company A&G is allocated to each service using the Massachusetts method of allocating A&G. This method is a multi-factor approach that uses an equally weighted average of three ratios: direct labor, plant in service and total revenue. These expenses for the Electric service are then further allocated based on a factor derived by actual Transmission-specific labor applied against total actual labor. For 2026, this allocation factor is calculated to be 10.4% and when applied against the actual A&G expenses, yields approximately \$7.8M of A&G. Table T1, lines 6 and 7 remove all FERC annual fees, Regulatory Commission Expenses, EPRI dues and non- safety advertising. Line 10 includes only Regulatory Commission Expenses related to transmission. For this projected rate year, Utilities has assumed zero values to be entered for lines 6, 7, and 10.
3. Electric common plant O&M (if any) in line 12 and transmission lease payments in line 13 are the final two items comprising Total Operating Expenses.

ii. Total Capital Projects Expenses include:

1. Debt Service Expense (Table T1, Line 15) is shown from the calculation of total Electric Debt Service as reflected on Table C3 and then allocated based on the transmission percentage of total gross plant. In debt issuances, Utilities, as a four- service utility,

first examines capital projects that need to be funded, either from bond issuances or cash and wholistically assesses the importance or criticality of each project in its projections for funding needs across each service. Once those projects are identified and planned, Utilities then assesses the required project funding needs to determine planned financing in conjunction with planned cash funding, to meet the required needs while still balancing critical financial metric targets related to debt coverage, debt ratio, and days cash on hand. Utilities then executes the planned financing through bond issuances. The debt service schedules on Table C3 specifically outline how much principal and interest is associated with the issuance and how much is attributed to the Electric service. These issuances and their allocated Electric percentages for principal and interest obligations are totaled up along with any actual debt that may have concluded in that year.

2. Cash-Funded New Construction Assets allocated to Transmission (Table T1, Line 24) starts with the actual Capital Additions assigned by function. Directly assigned Transmission Plant additions are combined with a portion of General Plant additions, based on the transmission percentage of total gross plant. A cash-funded allocator, derived from total actual cash funded capital against the total actual gross Electric plant additions from the prior 13 months, is then applied to the total Electric Capital assigned and allocated to Transmission yielding the actual total Cash Funding New Construction needs allocated to Transmission.
3. Amortization of Premium or Discount (Table T1, Line 27) is reflected on Table C4. These projected values are captured from accounts 428 and 429, consistent with the FERC Uniform System of Accounts. Then, with the same Electric percentages for a given issuance reflected with the debt service schedules, those values are totaled and then allocated further based on the transmission percentage of total gross plant.

iii. Other Taxes include:

1. Surplus Payments to the City and Franchise Fees (Table T1, Line 41) is reflected on Line 39. As mentioned earlier, Utilities is an enterprise of the City of Colorado Springs. As a governmental entity, Utilities is a tax-exempt entity. However, the City Charter of the City provides for the appropriation of any remaining surplus of net earnings to the general revenues of the City. Pursuant to its authority as the legislative body for the City and as the ratemaking body for Utilities, City Council has established planned Surplus Payments to the City for Utilities' Electric services. These payments are assessed on a fixed rate per kWh of actual sales inside the city. Additionally, Utilities Electric service incurs Franchise Fees expense related to providing Electric services to customers residing in other

neighboring cities or municipalities. The Surplus Payments to City and Franchise Fees expense is allocated to Transmission using the Net Plant Allocator (Table T2, Line 17).

2. The TFR Template provides for Labor-Related Taxes (Table T1, Line 33) and Plant-Related Taxes (Table T1, Line 38), but Utilities is not projected to include either in this ATRR filing.

iv. **Other Revenue Requirement items include:**

1. An allocation for debt service coverage is reflected on Table T1, Line 47. Strong financial metrics are an important aspect of maintaining bond ratings which can influence the interest rates Utilities pays on its debt. High ratings generally lead to lower borrowing costs which keep costs down overall for ratepayers. In order to maintain the favorable “AA” rating, Utilities must show adequate debt service coverage in addition to other metrics. Stable industries such as utilities usually find debt service coverage ratio in the range of 1.25 to 1.5 as adequate. Utilities has included 1.3 to help meet its debt service coverage obligations and support its current “AA” rating and then allocated based on the transmission percentage of total gross plant.
2. Revenue credit offset is based on other Electric revenues included in Account 456.1, consistent with the FERC Uniform System of Accounts. For this projected rate year, Utilities has not projected any revenue credits to be included in its ATRR.

- c) **Transmission Revenue True-Up Mechanism** – Historically, Utilities’ OATT utilized a stated rate approach where the projected ATRR was updated as needed and brought forward in a rate case before City Council, serving as Utilities’ regulatory body. In anticipation of transitioning to the SPP RTO, Utilities proposes to incorporate a true-up mechanism in the TFR Template. This adjustment will compare Utilities’ actual costs incurred during the calendar rate year to the actual revenues generated by the ATRR and resulting rates during the same period. Any over-recovery or under-recovery will be reflected as a reduction or increase to the Annual Update in the following projected year. Since 2026 will be the first year in the SPP RTO, Utilities does not have true up data from 2024 to incorporate in the 2026 projections. As a placeholder, Utilities has set the actual revenues equal to the actual revenue requirement for 2024 to nullify any increase or reduction to the projected 2026 ATRR. Utilities expects to incorporate a 2026 true up calculation to include applicable interest calculated in accordance with 18 C.F.R. § 35.19a, in 2027 for the projected 2028 ATRR.

- d) **TFR Peak Transmission Load Divisor** – The calculation of Utilities Peak Transmission Load Divisor (Table TRC, Line 5) is reflected on Table T3. For the 12-month period of January 2024 to December 2024, Utilities determined the day and hour of its peak network load for each month and then added to this the load amount associated with known entities taking firm network service. In order to

represent the future energy needs for the region under normal weather conditions for each month, projecting the monthly load values for 2026, which are reflected on Table P5, incorporates historical peak loads, economic drivers, and spot load forecast additions. The average monthly peak load (12 coincident peak methodology) is used as the rate divisor to determine the underlying rates for service under Schedule 7 Long-Term Firm and Short-Term Firm (Table TRC, Lines 6-12) Point-to-Point and Schedule 8 Non-Firm (Table TRC, Lines 13-18) Point-to-Point Transmission Service.

- e) **TFR and Annual Update Implementation Protocols** – Accompanying the TFR Template are implementation protocols (“Protocols”) which is the last component of the TFR. As mentioned earlier, these are procedures governing how the transmission rates are calculated and updated. They also establish how interested parties can submit discovery requests, review, verify and challenge the annual rate updates and the timelines associated with the procedures. As outlined in the Protocols accompanying the TFR Template, no later than September 1 of each year, Utilities shall calculate its projected ATRR for the following year in accordance with the TFR Template that will be included in Attachment H of SPP’s Tariff. These Protocols are based on the existing public process that Utilities has in place for reviewing proposed tariff changes. Interested parties will have the opportunity to submit written questions and responses to those written questions will be posted on the SPP website, Open Access Same Time Information System (“OASIS”), and Utilities website (csu.org). Additionally, Utilities will host a meeting to provide an opportunity for oral and written comments. Upon conclusion of the process, Utilities shall submit the final ATRR and resulting rates to FERC in an Informational Filing and shall request SPP to provide notice of the Informational Filing via an SPP email exploder list and by posting the docket number assigned to Utilities’ Informational Filing on SPP’s website and OASIS.
 - f) **ATRR established using the TFR and Summary** – The currently projected ATRR for 2026 is shown on Table TRC, Line 1 of the template in the amount of \$34,281,960. In addition to the resulting updated projected 2026 ATRR, the transmission charges outlined in FERC’s pro-forma Schedules 7 and 8, as referenced earlier in this Decision & Order, will be updated. The difference between Schedules 7 and 8 is that the non-firm (Schedule 8) point-to-point transmission service shall not exceed one month’s reservation for any one application. The TFR Template, 2026 ATRR, and Schedule 7 and 8 rates, and the accompanying Protocols will be filed with FERC via SPP on behalf of Utilities. The final numbers may differ slightly from what is contained in this report due to subsequent adjustments that could be requested or required by SPP or the FERC.
7. Additionally, for purposes of the FERC filing, Utilities will submit prepared direct testimony which encapsulates the information provided herein as that approach is more typical to FERC filings. This filing that SPP will make on Utilities’ behalf will outline how the ATRR for NITS and rates for Firm and Non-Firm Point-to-Point Service are calculated. The TFR methodology will facilitate annual updates without the burden of filing rate cases,

thereby streamlining the process and ensuring alignment with regulatory requirements. In conclusion, Utilities' preparation for joining the SPP RTO represents a strategic move to enhance operational efficiency, achieve financial savings, and ensure compliance with regulatory standards. The proposed changes and the establishment of a TFR are pivotal steps in this process, paving the way for a smoother transition and long-term benefits for Utilities and its customers.

8. Utilities included the Tables that comprise and reflect the currently proposed calculation of the Formula Rate in its TO filing in the section titled Transmission Owner Filing Formula Rate Tables Populated.
9. In addition to the proposed TO Filing, Utilities' 2026 Rate Case filing also proposes changes to the Electric Rate Schedules, revisions to the URR and the OATT, and completion of a PURPA evaluation.
10. The proposed effective dates for Utilities' tariff changes are November 1, 2025, January 1, 2026, April 1, 2026, and January 1, 2027.
11. Utilities filed its tariff changes with the City Auditor, Ms. Natalie Lovell, on August 8, 2025, and with a copy to the City Attorney on August 8, 2025. Utilities then filed the enterprise's formal proposals on September 9, 2025, with the City Clerk, Ms. Sarah Johnson, and a complete copy of the proposals was placed in the City Clerk's Office for public inspection. Electronic and physical copies of the filing were also provided to City Council members at the September 9, 2025, City Council meeting. Notice of the filing was published on-line at www.csu.org on September 9, 2025, and in *The Gazette* on September 11, 2025. These various notices and filings comply with the requirements of §12.1.108 of the City Code and the applicable provision of the Colorado Revised Statutes. Copies of the published and mailed notices are contained within the record. Additional public notice was provided through Utilities' website, www.csu.org, and a complete copy of the proposals was placed on that website for public inspection.
12. The information provided to City Council and held open for public inspection at the City Clerk's Office was supplemented by Utilities on October 1, 2025. The supplemental materials contained revisions to the proposed Net Metering tariff changes: (1) changing the billing demand charge determination to the average of daily highest 15-minute demands during On-Peak hours of a billing period, rather than a single peak demand, and (2) increases the proposed Access and Facilities, per kWh rates. The modifications to Utilities' original filing result in a median Net Metering customer seeing an electric bill increase of approximately \$25 per month, as opposed to \$50 per month under the original approach.
13. The information provided to City Council and held open for public inspection at the City Clerk's Office was supplemented a second time by Utilities on October 9, 2025. The supplemental materials contained:

- a) Revised information related to the proposed changes to the Electric Rate Schedules, OATT, and the Transmission Owner Filing, including updated resolutions, additional references for tariff clarity, and formatting corrections;
 - b) A clerical correction to Utilities' Rate Manual;
 - c) New Electric Tariff sheet revisions to include a reference to the ELL rate in the Electric Cost Adjustment and Electric Capacity Charge rates and to clarify billing determination for Interruptible Service Demand Credits;
 - d) The Office of the City Auditor's audit report;
 - e) A record of *ex parte* communications;
 - f) The legal notice affidavits of publication;
 - g) Public outreach information; and
 - h) The Notice of Intent to Present Witnesses of the Joint Solar Parties.
14. The Office of the City Auditor issued its findings on the proposed tariff changes prior to the rate hearing, dated October 2025, which found that the overall modifications included in the 2026 Rate Case Filing Reports and the supporting schedules for proposed rates and fees for the electric service were prepared accurately and consistently. A copy of that report is contained within the record.
 15. On October 14, 2025, the City Council held a public hearing concerning the proposed changes to the Electric Rate Schedules, OATT, PURPA action, Transmission Owner Filing, and URR. This hearing was conducted in accordance with §12.1.108 of the City Code, the procedural rules adopted by City Council, and the applicable provisions of state law.
 16. City Council President Lynette Crow-Iverson commenced the rate hearing.
 17. The presentations started with Mr. Christopher Bidlack, a Senior Attorney with the City Attorney's Office – Utilities Division. Mr. Bidlack briefed City Council on its power to establish rates, charges, and regulations for Utilities' services. In setting rates, charges, and regulations for Utilities' services, City Council is sitting as a legislative body because the setting of rates, charges, and regulations is necessary to carry out existing legislative policy of operating the various utility systems. However, unlike other legislative processes, the establishment of rates, charges, and regulations is analogous to a quasi-judicial proceeding and requires a decision based upon evidence in the record and the process is not subject to referendum or initiative.
 18. Mr. Bidlack provided information on the statutory and regulatory requirements on rate changes. Rates for Water and Wastewater service must be reasonable and appropriate in

light of all circumstances, City Code §12.1.108(F). Rates for Natural Gas and Electric service must be just, reasonable, sufficient, and not unduly discriminatory, City Code §12.1.108(E).

19. At the conclusion of his presentation, Mr. Bidlack polled the City Council Members concerning any *ex parte* communication that they may have had during the pendency of this proceeding. Several Council Members provided information on potential *ex parte* communications.
20. Council Member David Leinweber stated that he will be fair and impartial when evaluating the rate case before him, regardless of any prior comments he made.
21. Council Member Tom Bailey stated that prior to the rate hearing he received a number of emails from citizens and had a conversation with a neighbor. He also affirmed his ability to act fairly and impartially.
22. Council Member Brandy Williams noted that she attended Utilities' October 7, 2025, Energy Wise and Net Metering open house, but did not have any conversations while in attendance.
23. Councilmember Nancy Henjum stated that, after consultation with the City Attorney's Office, she (1) attended a Colorado Solar and Storage Association ("COSSA") symposium, but did not discuss Utilities' rate case, and (2) watched a recording of Utilities' October 7, 2025, Energy Wise and Net Metering open house. She also affirmed her ability to remain fair and impartial.
24. Mr. Scott Shirola, Utilities' Pricing and Rates Manager, provided the enterprise's proposals.
25. Mr. Shirola started by providing a summary of Utilities' procedural compliance and the dates each compliance obligation was met. He then provided the 2026 Rate Case Overview, with proposed changes to the Electric Rate Schedules, URR, PURPA action, Transmission Owner Filing, and OATT.
26. Next, Mr. Shirola presented Utilities' proposed Large Load Rate Schedule. He noted that utilities across the country have developed similar rates based on the dramatic increase in large load customers. Utilities' proposed rate is based on the principles of (1) supporting economic development and rate competitiveness, (2) ensuring resource and infrastructure adequacy, (3) minimizing cost shifts to existing customers, (4) mitigating stranded cost risks, (5) protecting Utilities' financial health, and (6) supporting consistency with RTO provisions.
27. Based on those parameters, Mr. Shirola explained Utilities' proposed Industrial Service – Large Load Rate Schedule. The rate is applicable to customers with an electric load of greater than or equal to 10 MW and service conditions include: (1) a 10-year initial contract period, (2) customer responsibility for the cost of infrastructure extensions and

modifications, (3) customer being subject to and responsible for the costs of studies required by Utilities and the RTO, (4) customer responsibility for the costs of electric service acquired through power purchase agreements until adequate resources are obtained, (5) monthly bill provisions including, but not limited to, Access and Facilities per day, Demand Charge, Resource Adequacy Charge, System Support Charge, and Power Purchase Agreement pass through charges, (6) collateral requirements, and (7) payment of late fees.

28. Council Member Leinweber asked what will be done to ensure that the 10-year contract is binding on the Large Load customers and what is to stop them from leaving Utilities' service territory prior to the expiration.
29. Mr. Travas Deal, Utilities' Chief Executive Officer, explained that Large Load customers will be required to pay up front for infrastructure costs related to their utility service and that over the course of their 10-year contract they will be paying into reserves to support Utilities' ability to meet the needs associated with their status as a customer.
30. Additionally, Mr. Shirola noted that Large Load customers will be contractually responsible for minimum bills throughout their contract period and will be required to maintain a rolling 36-month collateral posting. Furthermore, there are charges applicable during a Large Load customer's first 10-year contract period that provide marginal costs to fund resources long term.
31. Council Member Leinweber furthered his question, asking how water resources are addressed for Large Load customers, noting that it was outside the scope of the discussed electric rate. Mr. Shirola explained that water costs are included in the URR Large User application fees for all four utility services, to be discussed later in Utilities' presentation.
32. Council Member Roland Rainey asked whether Utilities' participation in the SPP RTO would impose any restrictions related to on-peak and/or off-peak energy usage. Mr. Shirola explained that while SPP RTO participation may present opportunities to find cost advantages in energy purchases, it will not impact the base rates being discussed.
33. Mr. Shirola then presented Utilities' proposed change to the Contract Service – Military Wheeling (ECW) rate which is being modified to address Utilities' transition into the SPP RTO by bringing the transmission costs applicable to the rate from the OATT into the ECW rate, as it relates to Military customer's receipt of federal hydroelectric power energy.
34. Council Member Henjum asked for further explanation for the need for the ECW change. Mr. Shirola explained that Utilities' military customers indicated that they did not wish to participate directly in the SPP RTO and that the proposed change allows Utilities to maintain costs and provide a simpler approach for the Military customers per their request.
35. Next, Mr. Shirola presented Utilities' proposed changes to the URR.

36. Council Member Henjum asked whether the remaining issues related to Electric Service in Utilities' filing documents were still to be presented, to which Mr. Shirola confirmed that they were.
37. Mr. Shirola's presentation of the proposed URR changes addressed: (1) Electric Industrial Service – Large Load – Addition of substation and transmission fees and the addition of recovery agreements for advance transmission cost related to development of mixed use, commercial, and/or industrial sites; (2) Large Load Requirements Study Fee – Clarification and changes to the URR provisions added in 2025 related to large load requirements/interconnection studies, including reducing the minimum load sizes requiring payment of study fees; and (3) Hydraulic Analysis Report (HAR) – Addition of a \$200/hour fee for minor HARs meeting requirements enabling them to be performed under the basic HAR fee of \$1,600.
38. Mr. Shirola then noted that clerical corrections are proposed for the Electric Rate Schedules, URR, and OATT, specifically noting that the corrections include a reference correction with the Community Solar Garden program and changes to better explain methods used and add language clarity.
39. To address a procedural requirement, Mr. Shirola shifted to the PURPA evaluation and recommended that City Council close the proceeding opened in 2022, with finding that existing Energy Wise rate schedules, programs, and practices sufficiently address the new load response and electric vehicle standards, and no additional action is required.
40. Next, Mr. Shirola presented Utilities' proposed changes to the OATT based on Utilities' joining the SPP RTO. In addition to the clerical change above addressing a typographical error to a single date, the proposals are to (1) rescind the OATT upon Utilities officially joining the SPP RTO and (2) approve Utilities' Transmission Owner Filing. Both proposals would be effective on the date Utilities joins the SPP RTO, which is anticipated to be April 1, 2026.
41. Next, Mr. Shirola presented Utilities' proposed changes to Net Metering. He started by explaining Utilities' shift to Energy Wise rates and the benefits they provide in reducing peak electric use and creating customer optionality. Net Metering rates were not modified in the initial Energy Wise roll-out and Utilities' proposed changes bring Net Metering customers in-line with the Energy Wise rates.
42. Mr. Shirola then provided a summary of the State of Colorado Renewable Energy Standard that established Net Metering requirements across the state in C.R.S. § 40-2-124. The requirements include: (1) Offset monthly consumption, with real time offset and one to one exchange throughout the month, (2) Monthly excess generation carried forward from month to month and one to one exchange within the calendar year, (3) Treatment of annual excess generation, (4) Nondiscriminatory rates, (5) Interconnection standards, and (6) Size specifications.

43. He noted that Net Metering is not storage of excess generation for customer's use in future periods nor selling of excess generation to utility providers.
44. Subsequently, Mr. Shirola explained the process a customer follows to install solar equipment at their location and enroll in the Net Metering program. A customer who has decided to install solar equipment must choose a third-party solar installer, submit an application to Utilities for Utilities' review and approval, acquire the applicable permits, and request meter installation and activation. A customer's solar system must comply with applicable electric and building codes, Utilities' Electric Line Extension and Service Standards, and applicable regulations. The Net Metering agreement required by all Net Metering customers is subject to present and future laws, rules and regulations, and Utilities' Tariffs, as amended. Utilities has never sold a solar system and does not advise customers on viability of a solar system purchase for their home.
45. Utilities established its Renewable Energy Net Metering Service in 2005 to follow the requirements of the State law applicable to municipal utilities. There are currently approximately 9,000 customers on the rate; with approximately 1,000 customers joining each year since 2021. Rebates for rooftop solar systems from Utilities started in 2006 and were periodically reduced over time and ended completely in 2022.
46. Council Member Henjum asked Mr. Shirola to repeat the history of solar incentives. Mr. Shirola provided the summary, noting that rates historically associated with rooftop solar have been an incentive to the solar industry in addition to the rebates mentioned.
47. Council Member Leinweber asked how Net Metering customers' rooftop solar has contributed to Utilities' compliance with State of Colorado mandated renewable energy standards. To which Mr. Shirola noted that the question would be addressed subsequently in Utilities' presentation.
48. Next, Mr. Shirola provided a chart listing a summary of discussions Utilities held with the Colorado Springs Utilities Board of Directors ("Utilities Board") relating to Energy Wise rates and Net Metering between 2018 and 2025.
49. Council Member Henjum expressed her concern that the model used in Utilities' proposed changes to Net Metering were not communicated to the Utilities Board prior to the Utilities Board Working Committee on August 18, 2025; and that while there had been prior discussions related to Net Metering, she did not recall any on the proposed model.
50. Council Member Williams requested confirmation that the proposed changes to Net Metering are recent developments, with prior discussions and changes being related to solar system capacity limits and the adoption of an application fee, which was not charged at the implementation of the program. Mr. Shirola confirmed Council Member Williams' statement and noted that several changes to the cash out process were also made previously.
51. Council Member Leinweber asked why solar customers were not included in the initial development of the Energy Wise rates and how solar customers could benefit from the

rates. He also explained his belief that Colorado Springs is a community that believes in conservation and wants to do the right thing, and that financial incentives can help the community reach those goals. He also expressed his understanding that Utilities did not include Net Metering in the initial Energy Wise process because of the ongoing state discussions.

52. Mr. Shirola provided a summary of Utilities' participation in the 2024 Colorado Net Metering Working Group led by the Colorado Energy Office. Ultimately, the working group, involving the solar industry, electric utilities, consumer advocates, organized labor, environmental conservation groups, and local governments, was unable to reach consensus on any reforms to Net Metering.
53. Council Member Williams asked what prompted the statewide discussion of Net Metering. Mr. Shirola answered that the conversation was driven by multiple utilities proposing methods of modifying Net Metering, with concepts such as a delivery charge and grid access charges.
54. City Council then took a five-minute recess.
55. Next, Mr. Shirola explained the breakdown of rate components and noted the impact of solar generation as a whole on Utilities energy portfolio and noted that utility scale solar generation provides more renewable energy than behind the meter solar, at a cheaper cost. Utilities' Net Metering customers produce a collective, name plate capacity of approximately 50 MW. Utilities' portfolio includes approximately 290 MW of utility scale renewable energy. The cost of utility scale renewable generation is less than \$0.03 per kWh, while Net Metering generation is currently exchanged at \$0.12 per kWh.
56. Council Member Henjum noted that 50 MW is a substantial source of electric capacity.
57. Mr. Shirola then moved to an explanation of the electric Cost of Service Study and its relation to Utilities proposed changes to Net Metering. He broke costs into those applicable to the customer, energy, and demand. Demand costs do not vary based on a customer's energy consumption, but vary based on the customer's level of peak usage. The peak usage level sets the capacity needed to serve a customer. The current rate design for Net Metering customers does not address demand, and thus does not correctly collect it in the context of the credits that are provided through the rate. As such the current rate under-quantifies the energy consumed by Net Metering customers from Utilities' electric system.
58. Council Member Williams expressed her concern with the fact that Utilities modified the information presented throughout the rate case process. She further stated that while she appreciates the change to the proposed demand charge averaging customers' peak usage, she does not support moving forward with Utilities' proposed changes.
59. Council Member Dave Donelson asked whether the presentation slide addressing a Net Metering system's interaction with Utilities' electric system has changed. Mr. Shirola

confirmed that the table was updated to be reflective of the median Net Metering customer, but that the scope of the slide has not changed.

60. Council Member Henjum asked how the provided interaction chart compared to what was in Utilities' initial filing and what was the base of data sampling. Mr. Shirola answered that the slide is intended to show a typical customer's hourly interactions with the electric system and that data sources will be addressed throughout the remainder of the presentation.
61. Council Member Leinweber commented that the vast majority of Utilities' customers are not Net Metering customers and that the proposed changes attempt to align Net Metering customers with the overall Energy Wise program. Additionally, non-Net Metering customers will be paying a premium rate during on-peak hours.
62. Additionally, Council Member Leinweber noted that, if a Net Metering customer has a battery as part of their system, they are able to store their own energy which can be used during peak hours, and asked if customers have been encouraged to install batteries. Mr. Shirola furthered that Net Metering customers with batteries present a different dynamic as it allows those customers to store energy at their premises.
63. Council Member Henjum noted language from Utilities' rate case filing regarding the under-quantification of energy usage by Net Metering customers and the associated cost shifting. Mr. Shirola responded that residential rates are designed to collect the overall revenue requirement for the residential customer class. The overall cost remains constant even if Net Metering customers do not provide all of the costs associated with their energy usage. As a result, other residential rates are set higher to collect the amount that is under-recovered from the Net Metering portion of the residential class.
64. Council Member Williams expressed her frustration that Utilities, and previous Utilities Boards, have known of the Net Metering under-collection for the entirety of the program, but have not acted until this filing. She expressed her position that a different conversation is needed to establish a path from the status quo to resolving the under-collection.
65. In response, Mr. Shirola said that while the cost shift is a known issue, the exponential growth in Net Metering customers is the factor that drove Utilities to its proposed changes.
66. Council Member Williams restated her position that the discussion should have started when far fewer customers were on the rate.
67. Mr. Tristan Gearhart, Utilities' Chief Planning and Finance Officer, addressed several questions. He explained that renewable energy credits ("RECs") acquired through rebates provided to Net Metering customers do provide value to Utilities and all its customers. In 2022 the rebate program was discontinued, so RECs are no longer being acquired as the number of Net Metering customers increases dramatically. Additionally, Utilities would like to see the Net Metering process align with the Energy Wise process, but felt it was valuable to let the State working group evaluation move forward prior to acting. Lastly,

he noted that the January 1, 2027, effective date for the proposed changes provides additional time for communication with customers.

68. Mr. Deal explained that Utilities' addition of large-scale solar generation coming online allows Utilities to acquire lower price renewable resources than were available at the commencement of the Net Metering Program.
69. Council Member Leinweber commented that solar installers should change their approaches to take advantage of afternoon sun and evaluate battery options.
70. President Crow-Iverson stated that the lunch recess would be taken.
71. Upon return, Mr. Shirola reiterated the summary of Utilities' Net Metering customers' overall energy usage in relation to the energy produced.
72. Council Member Leinweber commented to highlight the importance of the time of day in which cost to deliver energy is the highest and the fact that it aligns with less solar production. This emphasizes why there is not an equitable trade of energy from off-peak to on-peak times, as they inherently have different values. Non-solar customers want the cheapest energy to purchase, which creates the need to balance costs between customers and energy costs.
73. Mr. Shirola noted that the requirement established by State law for a one to one exchange under the Net Metering program creates many of the difficulties being discussed.
74. Then, Mr. Shirola moved to a discussion of the cost impacts of Net Metering to Utilities and the methods of rate making used to transition to the Energy Wise program. He noted that under the current approach Net Metering customers shift costs to non-Net Metering customers, with a typical annual cost shift of approximately \$600 per Net Metering Customer, with a total impact of \$5.5 million to remaining residential customers. The total shifted cost impacts a sample non-Net Metering customer by approximately \$25 per year.
75. Council Member Henjum asked Mr. Shirola to provide additional context on the cost shift evaluation. Mr. Shirola explained that the cost shift study is based on an overall residential sample size of over 700 customers, as selected by Utilities' consultant. Within that sample, 28 Net Metering customers were selected as the net metering representation of the overall residential customer class, approximately 4.5%. That study was used solely to estimate the cost shifts and showed the level of under-collection per year. The proposed changes to rates are not based on the sample of 28, but the overall class usage.
76. Mr. Shirola noted that this type of cost shift or subsidy is comparable to many other utilities.
77. Council Member Henjum asked Utilities to explain what the value of solar generation by solar customers during the generation period is to Utilities. Mr. Shirola commented that a benefit was RECs acquired through the rebates when those were in effect, which allowed

the rest of Utilities' customers to benefit from meeting the state mandate and Utilities' ability to avoid purchasing, or generating, some amount of power during the day.

78. Council Member Henjum followed up by asking if the value of the generation was considered in the calculation. Mr. Shirola replied that the rates are based on the cost of service of providing service to Net Metering customers, no changes are being proposed to the fuel rate components, and Net Metering customers continue to get the value of the base rate energy charge and Electric Cost Adjustment rate components.
79. Mr. Gearhart further noted that in the middle of the day, there is energy that is much less expensive than what is produced by Net Metering, as result the energy produced by Net Metering customers may not be used in support of off-peak system use. Additionally, Utilities must provide an electric system for the Net Metering customers sufficient to meet their on-peak and nighttime usage.
80. Council Member Henjum asked whether there is any capacity in Utilities' existing batteries to store rooftop solar energy production. Mr. Gearhart explained that Utilities uses batteries to store the lowest cost energy available, which would not include Net Metering produced energy. Net Metering energy is four to five times more expensive than energy produced by utility scale solar arrays.
81. Mr. Gearhart noted that Net Metering State requirements provide limited ability to recover demand costs through volumetric energy charge. Net Metering allows excess solar generation to be carried forward and offset energy in future periods. Furthermore, the approach presented by Utilities is also recommended by its consultant. Ultimately, Utilities must recover the cost of providing service and the current rate does not do so.
82. Based on these factors, Mr. Shirola explained Utilities' proposed changes to Net Metering Service. The changes are driven based on establishing rates that are just, reasonable, and not unduly discriminatory and Utilities' Rate Design Guidelines which prioritize, in order: (1) Economic Efficiency, (2) Revenue Stability, (3) Equitability for All Customers, (4) Customer Satisfaction, and (5) Customer Bill Stability. These standards require the proposed Net Metering changes to eliminate the current under-collection.
83. Council Member Henjum explained that the rate design guidelines cut to the core of her struggle with Utilities' proposed Net Metering changes. While she supports the guidelines and the need to address the reality of the costs presented, she struggles with the timeline on which the proposed changes were provided and believes the process missed addressing customer satisfaction and created a situation customers perceive as inequitable and a threat to bill stability. She does not believe Utilities provided Utilities Board and City Council the time to fully evaluate the proposal and that the process should have been carried out over a longer period of time.
84. Mr. Gearhart acknowledged the concerns regarding Utilities' timing, but confirmed that Utilities' rate case filing complied with legal obligations and provided that the rate change will not go into effect for one year. He also noted his belief that the proposed changes need

to be viewed within the scope of all Utilities' customers, not just Net Metering customers. Rates must be presented to address under-collection in the best possible method and other residential customers should not be asked to subsidize rooftop solar.

85. Council Member Williams questioned Utilities' urgency for a change presently if the issue has been in place for a number of years and urged that the process does not need to be rushed. She also commented that she does not believe she was given sufficient opportunity to review the proposed changes and potential alternatives as a Utilities Board member.
86. Council Member Rainey asked if Utilities engaged with the solar industry to gauge their input on the proposed changes. Mr. Gearhart stated that broad level work has been done by Utilities with the large-scale solar industry and that Utilities is not currently sending the right price signal to the rooftop solar industry in Colorado Springs.
87. Next, Council Member Rainey asked what a ratepayer's incentive to acquire solar panels would be under the proposed changes. Mr. Gearhart said that a customer must evaluate their purchase of solar panels individually and in the context of the then current rates. Utilities does not guarantee static rates, as they must be set to recover costs over time.
88. Council Member Bailey expressed his position that City Council must address the situation at the table currently and that there is not any value in relitigating the actions of past decision makers. He believes that Utilities' proposed changes are an appropriate method to address the subsidy and that they should be approved to avoid pushing the issue further down the road.
89. Mr. Gearhart then summarized the details of Utilities' proposed changes to Net Metering. Utilities proposed the addition of a Renewable Energy Net Metering rate, to include an Access and Facilities, per Day Charge, Access and Facilities, Per kWh Charge, Demand Charge, per kW per Day; each with applicability to Residential and Commercial Customers. The proposal would migrate all Residential and Commercial Net Metering Customers from Frozen to new Renewable Energy Net Metering rates. Additionally, the change would migrate any Industrial Net Metering customers from Frozen to Energy Wise standard rates.
90. Additionally, Mr. Gearhart explained that the proposed changes: (1) continue traditional Net Metering of energy charges at a one to one exchange; (2) recognize peak cost aligning rates with the cost of providing service through the addition of a demand charge; (3) maintain a commitment to Net Metering with sustainable rate design; and (4) empower customers to control their bill by shifting usage to off-peak periods or spreading usage across on-peak periods.
91. Council Member Henjum noted her appreciation that Utilities modified its proposal through its supplemental filing, but emphasized that such a change would not have been necessary if customers had been involved for a longer time period and questioned what additional improvements could be achieved through additional customer involvement.

92. Mr. Gearhart explained that Utilities' initial proposed demand charge related to a customer's highest on-peak usage in a billing period aligned with industry standard, but that Utilities found several examples of other utilities that use the now presented averaging methodology.
93. Mr. Gearhart concluded the Net Metering portion of Utilities' presentation by listing Utilities' key Net Metering rate considerations: (1) Solar does not generate electricity 24-hours per day; (2) Utilities' customers do have 24/7 access to Utilities electric grid and resources to serve their electricity needs; (3) Utilities has an obligation to serve the energy needs of its customers; (4) Current Net Metering rates shift the costs of needed infrastructure to other, non-Net Metering customers; (5) Utilities is directed by City Council and the Utilities Board to ensure pricing practices that result in just, reasonable, and not unduly discriminatory rates; and (6) Without direction from City Council to change current Net Metering rates, costs will continue to shift from one set of customers to another.
94. Next, Mr. Gearhart provided a summary of Utilities' customer outreach, which included communication through the csu.org website, general customer emails, Utilities Board meetings, Media interviews, one-on-one meetings and calls, direct customer emails and responses, and the October 7, 2025, Energy Wise and Net Metering open house.
95. The October 7, 2025, Energy Wise and Net Metering open house was held at the Ent Center for the Arts at the University of Colorado, Colorado Springs from 5:30 to 7:00 p.m. It consisted of an Energy Wise open house and Net Metering presentation and moderated Q&A.
96. Council Member Rainey expressed his appreciation to Utilities for holding the open house based on his prior request to do so.
97. City Council next took a five-minute recess.
98. Ms. Natalie Lovell, the City Auditor, then provided comments on her office's review of Utilities' proposals. Ms. Lovell explained that her office is not recommending or opposing any of Utilities' proposed changes, but verifies that the math, methodology, and documentation presented is accurate. Her office's review concluded that the proposed rates and proposed documents were prepared accurately and that the proposed changes are consistent with Utilities Board Direction.
99. After Utilities' presentation, President Crow-Iverson opened the floor for public comment.
100. The Joint Solar Parties, representing the Colorado Solar and Storage Association ("COSSA"), Solar United Neighbors ("SUN"), and certain Colorado Springs Utilities ratepayers, including Tanner Cox and Scott Carter, submitted a request for presentation of witnesses on October 3, 2025, in relation to the proposed Net Metering modifications.
101. The Joint Solar Parties noted an intent to provide comments from KC Becker, CEO, COSSA; Ellen Howard Kutzer, General Counsel, COSSA; Wil Gehl, Senior Manager,

State Affairs, Intermountain West Region, Solar Energy Industries Association; Tanner Cox, Colorado Program Direction, SUN and Utilities ratepayer; and Scott Carter, Utilities ratepayer.

102. President Crow-Iverson granted the Joint Solar Parties a total of 15-minutes of time to comment, to be allocated amongst their group at their discretion.

- a) Mr. Cox started the Joint Solar Parties' presentation. He stated that Net Metering is a crediting system that recognizes the energy solar customers send to the grid and saves the applicable utility on generation and transmission costs. The Net Metering credit is provided for the service provided by solar customers to the grid. He does not agree that solar customers shift any costs between rate classes and emphasized that solar is available for customers from all walks of life. He stated that the proposal should be rejected.
- b) Next, Ms. Becker argued that the proposed Net Metering changes are not in compliance with state law, specifically that this is not an issue of local concern, but a matter of statewide concern. Additionally, Ms. Becker stated that the solar subsidy claim is over blown, and the proposed changes are bad public policy. She also stated that existing solar customers should be grandfathered and proposed changes will reduce new solar and therefore reduce resiliency. Ms. Becker noted that she previously submitted several Colorado Open Records Act ("CORA") requests and that she continues to wait for Utilities' disclosure of documents. She concluded that the rate proposal process has not been transparent and that City Council should reject the proposed changes.
- c) Then, Ms. Kutzer contended that the proposed Net Metering changes are prohibited and discriminatory as they include costs that cannot be offset by solar production, while also echoing Ms. Becker's comments.
- d) Council Member Henjum requested additional time for the Joint Solar Parties, with Council President Crow-Iverson granting an additional five minutes.
- e) Ms. Kutzer added to her argument that the proposed demand charge approach taken is confusing and fails to address issues noted by Utilities' consultant.
- f) Mr. Carter concluded the Joint Solar Parties' testimony with his contention that the proposed changes to Net Metering are irreparably flawed and fail to properly account for the benefit provided by Net Metering customers.
- g) The Joint Solar Parties requested that their written comments be considered, that the proposed changes be rejected, and that any future Net Metering evaluations be done with input from the solar industry.

103. Council Member Henjum requested that Utilities address the points presented by the Joint Solar Parties during its response opportunity.

104. Public comment was then provided by 44 citizens and ratepayers. All speakers spoke in opposition to Utilities proposed Net Metering modifications. The speakers' objections to the proposed changes followed the following themes:

- a) The proposed changes significantly diminish the value of the investment Net Metering customers have made in their solar systems.
- b) The proposed changes fail to account for the full benefits Net Metering provides to Utilities' electric system.
- c) The proposed changes should be tabled so that all stakeholders can be involved in evaluating the best path forward for Net Metering.
- d) Existing Net Metering customers should be grandfathered into the existing Net Metering rate.
- e) The proposed changes are punitive and punish customers with rooftop solar systems.
- f) Utilities should invest in battery systems to be able to best use the energy produced by Net Metering customers, or alternatively, incentivize customer batteries.
- g) The proposed changes harm the energy transition to renewable energy.
- h) Existing Net Metering agreements with customers prohibit the proposed changes.
- i) Utilities previously encouraged customers to install solar systems, and the proposed changes are contrary to that prior action.
- j) The proposed changes are discriminatory and unlawful.
- k) The proposed changes will damage the local solar industry.
- l) The current rate process has not been transparent or well communicated, and as a result, has eroded the public's trust in Utilities.
- m) The deficiencies in the Net Metering program are a result of Utilities' mismanagement and should have been corrected when they first became apparent.

105. City Council then took a ten-minute recess.

106. Following the opportunity for public comment, President Crow-Iverson opened the floor to questions or comments from City Council.

107. Council Member Henjum provided a list of questions for Utilities:

- a) At what point were customers made aware of the proposed changes to Net Metering?
- b) When did Utilities determine that the methodology for the proposed Net Metering changes would be used?
- c) Why is Utilities comfortable with the changes it proposed to Net Metering in the October 1, 2025, supplemental filing?
- d) Because many people do not understand the proposed Net Metering methodology and the cost shift calculations, present the calculations of each and include the benefit of rooftop solar in doing so.
- e) How did Utilities fail to understand the level of response it would receive from Net Metering customers in response to the proposed changes?
- f) Accepting that Net Metering was not included in the 2025 transition to Energy Wise rates, when did Utilities plan to bring the Utilities Board into the Net Metering conversation?
- g) Did Utilities think about the word choice implications when using the word “subsidy”?

108. Council Member Rainey then provided additional questions to be addressed by Utilities:

- a) Would Utilities comment on the CORA request mentioned by the Joint Solar Parties?
- b) Could Utilities provide clarity on the rate filing’s proposed changes to Net Metering compliance with applicable law?
- c) What would be the outcome of grandfathering existing Net Metering customers to the current rate?
- d) Has Utilities evaluated increasing its investment in battery storage facilities?

109. Next, Utilities presented its answers and commentary to the questions that were contributed by the public and City Council.

110. Mr. Bidlack addressed the questions regarding legality. He started by explaining that Utilities is subject to the Colorado Renewable Energy Standard (as noted previously by Mr. Shirola and codified at C.R.S. § 40-2-124) which was put into place in 2004. However, municipal utilities such as Utilities are subject to different provisions of the Renewable Energy Standard than investor-owned utilities. While there are Net Metering requirements, such as the one for one crediting, there is additional local control.

111. In relation to discriminatory rates, Mr. Bidlack commented that customers being subject to different rates alone does not create discrimination. Discrimination is based on similarly situated customers being treated differently. It is up to City Council, as Utilities rate setting authority, to determine if the rates proposed by Utilities are just and reasonable.
112. Next, Mr. Bidlack noted that Utilities is not subject to regulation from the Colorado Public Utilities Commission. As a municipal utility, Utilities is regulated by City Council.
113. Lastly, Mr. Bidlack addressed Net Metering agreements. He explained that the agreements are binding contracts, but that they are specifically subject to Utilities' tariffs as they are amended from time to time.
114. Council Member Henjum asked Mr. Bidlack if the notice requirements associated with the Net Metering agreements were met and if there are any additional obligations that should be read into the agreements. Mr. Bidlack stated that the legal notice requirements were met and that it would be Utilities' decision as to whether any additional steps were warranted.
115. Mr. Gearhart then presented Utilities' responses to the remaining questions. Prefacing his comments with the statement that while there are benefits from Net Metering to Utilities, such as the RECs and compliance standards they help achieve, Utilities is seeking to avoid discrimination against non-Net Metering customers and that the impacts of Net Metering customers to the system must be accounted for. Ultimately, Utilities' electric system must be built to handle a Net Metering customer's maximum use of system infrastructure.
116. He explained that solar energy delivered during the day does not benefit on-peak usage. Additionally, imposing a demand charge on Net Metering customers is designed to address the usage concerns, not to remove the one to one credit standard.
117. In following Mr. Bidlack's comments on customer Net Metering agreements, Mr. Gearhart noted that recognition of changing rates within contracts is a requirement for municipal utilities given their structure.
118. From a timing perspective, Mr. Gearhart explained that Utilities started to look at demand charge concepts when peak usage information became available to Utilities. The decision to move forward with the presented mechanism was made over the summer of 2025.
119. In addressing Net Metering customers' return on investment in their solar infrastructure, Mr. Gearhart stated that Utilities is not in a position to back the personal investments of customers. Doing so would be discriminatory to non-solar customers. Many customers make investment decisions on appliances and other items that impact their utility usage.
120. In relation to grandfathering existing Net Metering customers, Mr. Gearhart explained that doing so would eliminate Utilities' ability to remove the cost shift that is taking place, and is thus not a proposal that Utilities felt was appropriate.

121. In response to questions regarding Utilities' confidence in the proposed Net Metering changes' ability to recover necessary costs following the supplemental filing, Mr. Gearhart noted that it is possible the move to a median customer and average peak use method of demand charge calculation may not cover the full Net Metering cost shift. However, he believes that it will be a positive step and will provide additional information into the overall impact of the methodology change.
122. Next, Mr. Gearhart addressed the distinctions between Utilities as a municipal utility and Xcel Energy, as an investor-owned utility. Xcel's for-profit status allows it to offer additional Net Metering rate options. For Utilities, there is potential to look for additional Net Metering rate options if an appropriate standard is first set. He also noted that customer batteries could provide additional paths to rate options for Net Metering customers.
123. Council Member Henjum asked Mr. Gearhart why Utilities has not explored potential Net Metering rate alternatives. Mr. Gearhart commented that establishment of a compliant program was a prerequisite to additional rate options, but that alternative options may be available in the future. Council Member Henjum noted her regret that the Utilities Board had not directed the Utilities Policy Advisory Committee to explore Net Metering.
124. In addressing Utilities' cost shift calculation, Mr. Gearhart explained that it is tied to the demand costs associated with customer usage and the infrastructure that is required to serve in that time frame. The one to one credit creates the shift based on when energy comes on the system vs. when energy is taken from the system. Numbers come from the 2025 Cost of Service Study.
125. Mr. Gearhart addressed the Energy Wise and Net Metering open house and explained that it was originally scheduled for Utilities' Leon Young Service Center, but was moved when a greater number of RSVPs were received than expected. The number of attendees also prompted the structural change, as individual conversations became impractical. He expressed a desire to continue conversations with customers.
126. Regarding the CORA request mentioned by the Joint Solar Parties, Ms. Renee Congdon, Division Chief, Colorado Springs City Attorney's Office – Utilities Division, explained that the specific CORA request resulted in the review of tens of thousands of documents, many requiring redaction or being withheld. As of the hearing date, approximately 30% of the records have been released and diligent work continues.
127. Lastly, Mr. Gearhart expressed his position that the use of the word "subsidy" is appropriate in describing the cost shift seen between customers.
128. Council Member Donelson then asked if Utilities would be willing to consider Net Metering alternatives during 2026 if the proposed changes were approved. Mr. Gearhart said that alternative rate options are possible.

129. Council Member Donelson next asked if generation across Utilities' system has a benefit to the system. Mr. Gearhart stated that the timing of energy generation is the key factor in its value to the system.
130. President Crow-Iverson determined that an executive session was not necessary.
131. Mr. Bidlack then polled City Council regarding the issues central to the Electric Rate Schedules, OATT, PURPA action, Transmission Owner Filing, and the URR. Per City Council's request, Mr. Bidlack did not present every Issue for Decision, but instead asked that City Council indicate approval of Utilities' proposals as a whole, excluding the proposed changes related to Net Metering. City Council indicated unanimous approval of those changes.
132. Mr. Bidlack then polled City Council regarding the proposed changes to Net Metering.
133. Council Member Henjum commented that additional time is warranted to evaluate the best approach to Net Metering and emphasized the value of rooftop solar generation.
134. Council Member Leinweber asked for clarification on the impact of City Council rejecting the proposed Net Metering changes. Mr. Bidlack indicated that a rejection of the current proposal does not preclude future action related to Net Metering.
135. Council Member Donelson expressed his position that a vote approving the proposed changes requires Net Metering customers to pay their fair share and that future changes would still be possible.
136. Council Member Rainey asked if a rejection of the proposed changes would set any specific timeline for reconsideration. Mr. Bidlack stated that no timeline would be created.
137. Following the additional City Council comment, Mr. Bidlack polled City Council for direction on the proposed Net Metering changes. City Council indicated a rejection of the proposed changes, by a poll of four in favor and five opposed.
138. Mr. Bidlack then restated the future schedule for Utilities' rate filing, with the draft Decisions and Orders being presented to City Council at the Council Work Session on October 27, 2025, and for final approval at the Regular City Council Meeting on October 28, 2025.
139. The following are the proposed changes and the votes by City Council addressing the Transmission Owner Filing:
- a) Should Utilities, so long as approved by the Federal Energy Regulatory Commission, make effective on the same date that Utilities' Open Access Transmission Tariff is rescinded, a formula rate template and the implementation protocols for establishing the mechanism and process for annual calculation, to

include any true-up and updates, of its Annual Transmission Revenue Requirement and underlying calculated rates?

The City Council held that Utilities **shall**, so long as approved by the Federal Energy Regulatory Commission, make effective on the same date that Utilities' Open Access Transmission Tariff is rescinded, a formula rate template and the implementation protocols for establishing the mechanism and process for annual calculation, to include any true-up and updates, of its Annual Transmission Revenue Requirement and underlying calculated rates.

- b) Should Utilities implement, on the same date that Utilities' Open Access Transmission Tariff is rescinded, Utilities' initial 2026 Annual Transmission Revenue Requirement and underlying calculated rates for Network Integration Transmission Service and Point-to-Point Transmission Service in the Colorado Springs Utilities zone of the SPP footprint?

The City Council held that Utilities **shall** implement, on the same date that Utilities' Open Access Transmission Tariff is rescinded, Utilities' initial 2026 Annual Transmission Revenue Requirement and underlying calculated rates for Network Integration Transmission Service and Point-to-Point Transmission Service in the Colorado Springs Utilities zone of the SPP footprint.

140. President Crow-Iverson then concluded the 2026 Rate Case Hearing.

ORDER

THEREFORE, IT IS HEREBY ORDERED that:

Utilities' Formula Rate as attached to the Resolution, so long as approved by the Federal Energy Regulatory Commission, is adopted and will be effective on the day on which Utilities' Open Access Transmission Tariff is rescinded and will remain in effect unless changed by subsequent transmission owner filings; and

Utilities' 2026 Annual Transmission Revenue Requirement and underlying calculated rates for Network Integration Transmission Service and Point-to-Point Transmission Service in the Colorado Springs Utilities zone of the Southwest Power Pool footprint as attached to the Resolution are adopted and will be effective on the day on which Utilities' Open Access Transmission Tariff is rescinded and will remain in effect unless changed by a subsequent Utilities' Annual Update in conformance with the Protocols.

Dated this 28th day of October, 2025.

CITY OF COLORADO SPRINGS

Council President

ATTEST:

City Clerk