RESOLUTION NO. 160 - 25

A RESOLUTION ADOPTING TRANSMISSION FORMULA RATE TEMPLATE AND THE IMPLEMENTATION PROTOCOLS FOR ESTABLISHING AN ANNUAL TRANSMISSION REVENUE REQUIREMENT FOR TRANSMISSION OWNER FILING SUBMITTALS FOR THE SOUTHWEST POWER POOL REGIONAL TRANSMISSION ORGANIZATION'S OPEN ACCESS TRANSMISSION TARIFF

WHEREAS, Colorado Springs Utilities ("Utilities") proposed to pursue membership in the Southwest Power Pool ("SPP") Regional Transmission Organization ("RTO") effective in accordance with SPP's quarterly onboarding schedule of new RTO members in 2026; and

WHEREAS, Utilities proposed to transfer functional control of its transmission facilities to SPP while continuing to own and maintain said infrastructure of its transmission system; and

WHEREAS, Utilities proposed to implement a formula rate template ("Template") and implementation protocols ("Protocols") (together the "Formula Rate"), so long as approved by the Federal Energy Regulatory Commission ("FERC"), to establish the mechanism and process for annual calculation, to include any true-up and updates, of the Annual Transmission Revenue Requirement ("ATRR") and underlying calculated rates for Network Integration Transmission Service ("NITS") and Point-to-Point Transmission Service in the Colorado Springs Utilities zone of the SPP footprint; and

WHEREAS, Utilities' proposed Formula Rate will be subsequently filed with FERC; and

WHEREAS, Utilities stated it may need to modify the proposed Formula Rate to address potential notifications, questions, requests, or requirements to facilitate FERC approval of the Formula Rate; and

WHEREAS, Utilities proposed to establish the Formula Rate and the 2026 ATRR with its underlying calculated rates to be effective on the day on which Utilities transfers functional control of Utilities' transmission facilities to SPP (scheduled for April 1, 2026, as of the date of this Resolution); and

WHEREAS, Utilities proposed to follow the established Protocols to adjust the ATRR for the Colorado Springs Utilities zone of the SPP footprint and the underlying calculated rates on an annual basis based on Utilities' projected cost-of-service and load for the prospective rate year through the required true-up adjustment ("Annual Update"), to submit such Annual Update to the FERC as an informational filing, and to enable SPP to provide notice of Utilities' Annual Update to interested persons; and

WHEREAS, if Utilities does become a member of SPP, the Formula Rate and the 2026 ATRR with its underlying calculated rates will be set forth in SPP's tariff and will supersede the existing rates in the Utilities' Open Access Transmission Tariff.

NOW, THEREFORE, BE IT RESOLVED BY THE CITY COUNCIL OF THE CITY OF COLORADO SPRINGS:

Section 1. That effective on the day on which Utilities transfers functional control of Utilities' transmission facilities to SPP (scheduled for April 1, 2026, as of the date of this Resolution), Utilities' Formula Rate, so long as approved by the FERC, shall remain in effect unless changed by subsequent transmission owner filings.

Section 2. That effective on the day of on which Utilities transfers functional control of Utilities' transmission facilities to SPP (scheduled for April 1, 2026, as of the date of this Resolution), Utilities' 2026 ATRR and underlying calculated rates for NITS and Point-to-Point Transmission Service in the Colorado Springs Utilities zone of the SPP footprint are approved and adopted and shall remain in effect unless changed by a subsequent Utilities' Annual Update in conformance with the Protocols.

Section 3. The attached proposed Template and proposed Protocols (which may be further modified due to subsequent adjustments requested or required by SPP or the FERC), supporting documents, Council Decision and Order, and other related matters are hereby approved and adopted.

Dated at Colorado Springs, Colorado, this 28th day of October 2025.

Lynette Crow-Iverson, Council President

ATTEST:

Sarah B. Johnson, City Clerk

COLORADO SPRINGS INCORPORATED SEAL SEPTEMBER 3, 1872 COLORADO

BEFORE THE CITY COUNCIL OF
THE CITY OF COLORADO SPRINGS

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

1. Colorado Springs Utilities, an enterprise of the City of Colorado Springs ("City"), a Colorado home-rule city and municipal corporation ("Utilities"), is a transmission provider and provides non-discriminatory wholesale high voltage electric service to itself and to its customers. Historically, Utilities has provided this service through the terms and conditions set forth in the Open Access Transmission Tariff ("OATT"). Utilities' OATT is a part of the collective tariffs that govern Utilities in accordance with the Colorado Springs City Code.

2. Utilities submitted the 2026 Rate Case, which proposes changes to the Electric Rate Schedules, Utilities Rules and Regulations ("URR"), the OATT, completion of a Public Utility Regulatory Policy Act ("PURPA") evaluation, and proposes a Transmission Owner ("TO") Filing pursuant to anticipated membership in the Southwest Power Pool ("SPP") Regional Transmission Organization ("RTO"). Utilities' filing included service specific reports, Resolutions, Tariff sheets, Worksheets, and TO Formula Rate Tables with full details.

3. Utilities' OATT was initially adopted in 2000 and revised periodically with updates in 2005, 2009, 2017-2019, 2022, and 2025. The updates in 2022 were driven by the opportunity to join the Western Energy Imbalance Service ("WEIS") market, an SPP market offering, which balanced generation and load amongst regionally participating utilities. The participation in the WEIS market provided access to a larger pool of resources enabling cost savings for Utilities. With the success of the WEIS market, SPP is expanding its current RTO westward. Utilities is currently preparing to make the transition to join the SPP RTO when it expands in April 2026.

4. As part of the transition to SPP, Utilities, as a TO, will transfer functional control of its transmission facilities to SPP but continue to own and maintain the physical infrastructure comprising its transmission system. Utilities' current OATT is proposed to be rescinded, and Utilities will submit TO filings to SPP for incorporation into the SPP open access transmission tariff ("SPP Tariff"), subject to Federal Energy Regulatory Commission ("FERC") approval of the methodology for setting rates. Generally, Utilities as a municipally owned entity, is not subject to the jurisdiction of FERC. However, FERC does regulate the wholesale electricity market, including transmission and sales between power generators and utilities to include the SPP RTO which requires justifying Utilities wholesale transmission rates in a different manner than historically done. Therefore, Utilities' rates and processes for updating its wholesale transmission have been prepared consistent with other municipal TO filings to regional transmission organizations and/or FERC.

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

Lynette Crow-Iverson

Council President

ATTEST:

Sarah B. Johnson

City Clerk

COLORADO SPRINGS INCORPORATED SEAL SEPTEMBER 3, 1872 COLORADO

Colorado Springs Utilities
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Projections for Rate Year 2026

Table of Contents

Table TRC

Table TRC: Transmission Rate Calculation

Projections for Rate Year 2026

Line No.	Item	Unit	Source/Calculation	Actual for 2024	Projected for 2026
[1]	Transmission Revenue Requirement Net of Revenue Credits	$/year	Table T1 or Table P1: [50]	$ -	$ -
[2]	True-Up (if Applicable)	$/year	Table P3: [14]	n/a	$ -
[3]	Schedule 11 Revenue incl. Schedule 11 True-Up	$/year	Table BP1: [3]	$ -	$ -
[4]	**Transmission Revenue Requirement Net of Schedule 11 Revenue**	**$/year**	**[1] + [2] - [3]**	**$ -**	**$ -**
[5]	Peak Transmission Load	kW	Table T3: [15] or Table P5: [15]		
	Schedule 7: Long-Term Firm and Short-Term Point-to-Point Transmission Service				
	The charges are as follows:				
[6]	Yearly Delivery	$/kW-year	[4] / [5]	$ -	$ -
[7]	Monthly Delivery	$/kW-month	[6] / 12	$ -	$ -
[8]	Weekly Delivery	$/kW-week	[6] / 52	$ -	$ -
[9]	Daily On-Peak Delivery	$/kW-day	[6] / 270	$ -	$ -
[10]	Daily Off-Peak Delivery	$/kW-day	[6] / 365	$ -	$ -
[11]	Hourly On-Peak Delivery	$/kWh	[9] / 16	$ -	$ -
[12]	Hourly Off-Peak Delivery	$/kWh	[10] / 24	$ -	$ -
	Schedule 8: Non-Firm Point-to-Point Transmission Service				
	The charges can be up to the following limits:				
[13]	Monthly Delivery	$/kW-month	[6] / 12	$ -	$ -
[14]	Weekly Delivery	$/kW-week	[6] / 52	$ -	$ -
[15]	Daily On-Peak Delivery	$/kW-day	[6] / 270	$ -	$ -
[16]	Daily Off-Peak Delivery	$/kW-day	[6] / 365	$ -	$ -
[17]	Hourly On-Peak Delivery	$/kWh	[15] / 16	$ -	$ -
[18]	Hourly Off-Peak Delivery	$/kWh	[16] / 24	$ -	$ -
[19]	**Schedule 11: Base Plan Upgrades**	**$/year**	**[3]**	**$ -**	**$ -**

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PROJECTED ATRR IS IN USE FOR THE PROJECTED RATE CALCULATION

Table BP1

Table BP1: Base Plan Upgrade Annual Transmission Revenue Requirement

Line No.	Item	Source/Calculation	Actual for 2024	Projected for 2026
[1]	Total Base Plan Upgrade Costs	Table BP3: [21]	$ -	$ -
[2]	Base Plan Upgrades True Up (if Applicable)	Table P3: [14]		$ -
[3]	**BASE PLAN UPGRADES ATRR**	**[1] + [2]**	**$ -**	**$ -**

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PROJECTED ATRR IS IN USE FOR THE PROJECTED RATE CALCULATION

Table BP2

Table BP2: Fixed Charge Rate Calculation

Line No.	Item	Source/Calculation	Actual for 2024	Projected for 2026
[1]	ATRR Net of Revenue Credits	Table T1: [48] or Table P1: [48]	$ -	$ -
[2]	Net Transmission Plant	Table T2: [16] or Table P2: [16]	$ -	$ -
[3]	**Default Fixed Charge Rate**	**[1]/[2]**		

Table BP3

Table BP3: Base Plan Upgrades Detail

Line No.	Project Name	Book Value in 2024	Book Value in 2026	Fixed Charge Rate for 2024	Fixed Charge Rate for 2026	To Actual ATRR for 2024	To Projected ATRR for 2026
[4]		$ -	$ -			$ -	$ -
[5]		$ -	$ -			$ -	$ -
[6]		$ -	$ -			$ -	$ -
[7]		$ -	$ -			$ -	$ -
[8]		$ -	$ -			$ -	$ -
[9]		$ -	$ -			$ -	$ -
[10]		$ -	$ -			$ -	$ -
[11]		$ -	$ -			$ -	$ -
[12]		$ -	$ -			$ -	$ -
[13]		$ -	$ -			$ -	$ -
[14]		$ -	$ -			$ -	$ -
[15]		$ -	$ -			$ -	$ -
[16]		$ -	$ -			$ -	$ -
[17]		$ -	$ -			$ -	$ -
[18]		$ -	$ -			$ -	$ -
[19]		$ -	$ -			$ -	$ -
[20]		$ -	$ -			$ -	$ -
[21]	**TOTAL BASE PLAN UPGRADES**					$ -	$ -

Notes:
Details on individual projects included in supplemental workpapers as needed.

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THIS SHEET IS IN USE FOR THE TRUE-UP RATE CALCULATION USING ACTUALS

Table T1

Table T1: 2024 Annual Transmission Revenue Requirement

Line No.	Item	Source/Calculation	Actual for 2024
Operating Expenses			
	Operations and Maintenance		
[1]	Transmission O&M Expense	Table E1: [A][31]	$ -
[2]	Load Dispatch	Table E1: [A][3]	$ -
[3]	Transmission by Others	Table E1: [A][15]	$ -
[4]	**Transmission O&M Less Load Dispatch and Transmission by Others**	**[1] - [2] - [3]**	**$ -**
	Administrative and General		
[5]	Total A&G Expense	Table E2: [A][15]	$ -
[6]	(Less) FERC Annual Fees	Internal Records, (Note A)	$ -
[7]	(Less) EPRI & Regulatory Commission Exp. & Non-safety Ad	Internal Records, (Note A)	$ -
[8]	Wage and Salary Allocator	Table T2: [3]	
[9]	Total A&G Expense Allocated to Transmission	SUM([5]:[7]) x [8]	$ -
[10]	Transmission Related Regulatory Commission Expense	Internal Records (Note C)	$ -
[11]	**Administrative and General Expense**	**[9] + [10]**	**$ -**
[12]	Common O&M Expense Allocated to Transmission	Internal Records, (Note B)	$ -
[13]	Transmission Lease Payments	Internal Records	$ -
[14]	**TOTAL OPERATING EXPENSES**	**[4] + [11] + [12] + [13]**	**$ -**

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Table T1

Table T1: 2024 Annual Transmission Revenue Requirement

Line No.	Item	Source/Calculation	Actual for 2024
Capital Projects			
	Debt Service		
[15]	Total Debt Service	Internal Records	$ -
[16]	Gross Plant Allocator - Transmission	Table T2: [9]	
[17]	**Total Debt Service Allocated to Transmission**	**[15] x [16]**	**$ -**
	Cash-Funded New Construction Assets		
[18]	Total Transmission Electric Capital	Table C1: [B][9]	$ -
[19]	Total General Electric Capital	Table C1: [D][9]	$ -
[20]	Gross Plant Allocator - Transmission	Table T2: [9]	
[21]	General Electric Capital Allocated to Transmission	[19] x [20]	$ -
[22]	Total Electric Capital Assigned and Allocated to Transmission	[18] + [21]	$ -
[23]	Cash-Funded Capital Allocator	Table T2: [20]	
[24]	**Total Cash-Funded New Construction Assets Allocated to Transmission**	[22] x [23]	$ -
	Amortization of Premium or Discount		
[25]	Amortization of Premium or Discount	Table C4: [F][51]	$ -
[26]	Gross Plant Allocator - Transmission	Table T2: [9]	
[27]	**Total Amortization of Premium or Discount Allocated to Transmission**	**[25] x [26]**	**$ -**
[28]	Interest on Commercial Paper Directly Assigned to Transmission	Internal Records, (Note D)	$ -
[29]	**TOTAL CAPITAL PROJECTS**	**[17] + [24] + [27] + [28]**	**$ -**

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THIS SHEET IS IN USE FOR THE TRUE-UP RATE CALCULATION USING ACTUALS

Table T1

Table T1: 2024 Annual Transmission Revenue Requirement

Line No.	Item	Source/Calculation	Actual for 2024
Other Taxes			
	Labor-Related Taxes	(Note E)	
[30]	Payroll	Internal Records	$ -
[31]	Highway and Vehicle	Internal Records	$ -
[32]	Wage and Salary Allocator	Table T2: [3]	
[33]	**Labor-Related Taxes Allocated to Transmission**	**([30] + [31]) x [32]**	**$ -**
	Plant-Related Taxes	(Note E)	
[34]	Property	Internal Records	$ -
[35]	Gross Reciepts	Internal Records	$ -
[36]	Other	Internal Records	$ -
[37]	Gross Plant Allocator - Transmission	Table T2: [9]	
[38]	**Plant-Related Taxes Allocated to Transmission**	**SUM([34]:[36]) x [37]**	**$ -**
	Surplus Payments to the City and Franchise Fees		
[39]	Surplus Payments to the City and Franchise Fees	Internal Records, (Note F)	$ -
[40]	Net Plant Allocator	Table T2: [17]	
[41]	**Surplus Payments and Franchise Fees Allocated to Transmission**	[39] x [40]	**$ -**
[42]	**TOTAL OTHER TAXES**	**[33] + [38] + [41]**	**$ -**

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THIS SHEET IS IN USE FOR THE TRUE-UP RATE CALCULATION USING ACTUALS

Table T1

Table T1: 2024 Annual Transmission Revenue Requirement

Line No.	Item	Source/Calculation	Actual for 2024
Revenue Requirement			
	Debt Service Coverage Allocation	(Note G)	
[43]	Total Debt Service	[15]	$ -
[44]	Required Cash for Debt Service Coverage	% of Debt Service	
[45]	Cash Available for Debt Service	[43] x [44]	$ -
[46]	Gross Plant Allocator - Transmission	Table T2: [9]	
[47]	**Debt Service Coverage Allocated to Transmission**	**[45] x [46]**	**$ -**
[48]	**TRANSMISSION REVENUE REQUIREMENT**	**[14] + [29] + [42] + [47]**	**$ -**
[49]	Revenue Credits	**Table E3: [16]**	$ -
[50]	**TRANSMISSION REVENUE REQUIREMENT NET OF REVENUE CREDITS**	**[48] - [49]**	**$ -**

Notes:

(A) EPRI Annual Membership Dues (within Account 930), All Regulatory Commission Expenses (Account 928), and non-safety related advertising (within Account 930). Source: TFR Backup, [WP2 O&M - A&G] tab

(B) Common expense includes operations and maintenance shared across Electric, Natural Gas, Water, and Wastewater Services that is allocated to transmission.

(C) Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting (within Account 928)

(D) Commercial Paper interest that can be directly assigned to Transmission operations. If commercial paper is issued on behalf of specific areas of operations then the interest expense incurred from the issuance of commercial paper for Transmission operations will be directly assigned to Transmission on this line.

(E) Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Formula Rate Template, since they are recovered elsewhere.

(F) CSU provides for surplus payments to the City in lieu of taxes, based on a fixed rate per kWh of electricity sales within the city. Franchise Fees are related to providing Electric Service to customers residing in other neighboring cities or municipalities.

(G) The utility must collect a percentage of Debt Service to meet its debt service coverage obligations.

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THIS SHEET IS IN USE FOR THE TRUE-UP RATE CALCULATION USING ACTUALS

Table T2

Table T2: Allocators Based on Actuals

For use in Revenue Requirement Calculation

Line No.	Item	Source/Calculation	Actual for 2024
	Labor		
[1]	Total Labor Expense	Internal Records	$ -
[2]	Transmission Labor Expense	Table E1: [B][31]	$ -
[3]	**Wage and Salary Allocator**	**[1] / [2]**	
	Plant		
[4]	Gross Plant in Service	Sum of: Table PD1, [18]	$ -
[5]	Gross Transmission Plant	Table PD1: [B][18]	$ -
[6]	General Plant	Table PD1: [D][18] + [E][18]	$ -
[7]	Wage and Salary Allocator	[3]	
[8]	General Plant Allocated to Transmission	[6] x [7]	$ -
[9]	**Gross Plant Allocator - Transmission**	**([5] + [8])/[4]**	
[10]	Accumulated Depreciation	Sum of Table PD2, [18]	$ -
[11]	Net Plant	[4] - [10]	$ -
[12]	Transmission Accumulated Depreciation	Table PD2: [B][18]	$ -
[13]	General Plant Accumulated Depreciation	Table PD2: [D][18] + [E][18]	$ -
[14]	Wage and Salary Allocator	[3]	
[15]	General Accumulated Depreciation Allocated to Transmission	[13] x [14]	$ -
[16]	Net Transmission Plant	[5] + [8] - [12] - [15]	$ -
[17]	**Net Plant Allocator**	**[16] / [11]**	
	Electric Capital		
[18]	Cash-Funded Capital Less CIAC and Adjustments	Table C1: [F][9]	$ -
[19]	Total Electric Capital Less Adjustments	Sum of Table C1: [A][9]:[D][9]	$ -
[20]	**Cash-Funded Capital Allocator**	**[18] / [19]**	

Notes:
[1] Total Labor Expense is the sum of Actual Year Budget from TFR Backup, [WP2 O&M - A&G] tab.

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THIS SHEET IS IN USE FOR THE TRUE-UP RATE CALCULATION USING ACTUALS

Table T3

Table T3: Load Divisor

MW

Line No.	Month [A]	Firm Network for Self [B]	Fountain Firm Network Service for Others [C]	Long-Term Firm Point to Point Reservations [D]	Other Long-Term Firm Service [E]	Short Term Firm Point to Point Reservation [F]	Transmission System Peak Load [G] SUM([B]:[F])	12-Month Coincident Peak Average [H] [G] - [F]
[1]	January	-	-	-	-	-	-	-
[2]	February	-	-	-	-	-	-	-
[3]	March	-	-	-	-	-	-	-
[4]	April	-	-	-	-	-	-	-
[5]	May	-	-	-	-	-	-	-
[6]	June	-	-	-	-	-	-	-
[7]	July	-	-	-	-	-	-	-
[8]	August	-	-	-	-	-	-	-
[9]	September	-	-	-	-	-	-	-
[10]	October	-	-	-	-	-	-	-
[11]	November	-	-	-	-	-	-	-
[12]	December	-	-	-	-	-	-	-
[13]	12-Month Total							-
[14]	12-Month CP Average							-
[15]	**12-Month CP Average (kW)**							**-**

Notes:
[H]: 12-month CP average includes all load with the exception of Short-Term Firm Point-to-Point load.
[13]: SUM([1]:[12]).
[14]: [13]/ 12.
[15]: [14] x 1000.

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THIS SHEET IS IN USE FOR THE PROJECTED RATE CALCULATION

Table P1

Table P1: Projected Annual Transmission Revenue Requirement

Line No.	Item	Source/Calculation	Projected for 2026
Operating Expenses			
	Operations and Maintenance		
[1]	Transmission O&M Expense	Table E1: [C][31]	$ -
[2]	Load Dispatch	Table E1: [C][3]	$ -
[3]	Transmission by Others	Table E1: [C][15]	$ -
[4]	**Transmission O&M Less Load Dispatch and Transmission by Others**	**[1] - [2] - [3]**	**$ -**
	Administrative and General		
[5]	Total A&G Expense	Table E2: [B][15]	$ -
[6]	(Less) FERC Annual Fees	Internal Records, (Note A)	$ -
[7]	(Less) EPRI & Regulatory Commission Exp. & Non-safety Ad	Internal Records, (Note A)	$ -
[8]	Wage and Salary Allocator	Table P2: [3]	
[9]	Total A&G Expense Allocated to Transmission	SUM([5]:[7]) x [8]	$ -
[10]	Transmission Related Regulatory Commission Expense	Internal Records (Note C)	$ -
[11]	**Administrative and General Expense**	**[9] + [10]**	**$ -**
[12]	Common O&M Expense Allocated to Transmission	Internal Records, (Note B)	$ -
[13]	Transmission Lease Payments	Internal Records	$ -
[14]	**TOTAL OPERATING EXPENSES**	**[4] + [11] + [12] + [13]**	**$ -**

THIS SHEET IS IN USE FOR THE PROJECTED RATE CALCULATION

Table P1

Table P1: Projected Annual Transmission Revenue Requirement

Line No.	Item	Source/Calculation	Projected for 2026
Capital Projects			
	Debt Service		
[15]	Total Debt Service	Table C3: [G][52] x 1000	$ -
[16]	Gross Plant Allocator - Transmission	Table P2: [9]	
[17]	**Total Debt Service Allocated to Transmission**	**[15] x [16]**	**$ -**
	Cash-Funded New Construction Assets		
[18]	Projected Transmission Capital Additions	Table P4: [B][9]	$ -
[19]	Projected General Capital Additions	Table P4: [D][9]	$ -
[20]	Gross Plant Allocator - Transmission	Table P2: [9]	
[21]	General Electric Capital Allocated to Transmission	[19] x [20]	$ -
[22]	Total Electric Capital Assigned and Allocated to Transmission	[18] + [21]	$ -
[23]	Cash-Funded Capital Allocator	Table P2: [20]	
[24]	**Total Cash-Funded New Construction Assets Allocated to Transmission**	**[22] x [23]**	**$ -**
	Amortization of Premium or Discount		
[25]	Amortization of Premium or Discount	Table C4: [F][51]	$ -
[26]	Gross Plant Allocator - Transmission	Table P2: [9]	
[27]	**Total Amortization of Premium or Discount Allocated to Transmission**	**[25] x [26]**	**$ -**
[28]	Interest on Commercial Paper Directly Assigned to Transmission	Internal Records, (Note D)	$ -
[29]	**TOTAL CAPITAL PROJECTS**	**[17] + [24] + [27] + [28]**	**$ -**

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THIS SHEET IS IN USE FOR THE PROJECTED RATE CALCULATION

Table P1

Table P1: Projected Annual Transmission Revenue Requirement

Line No.	Item	Source/Calculation	Projected for 2026
Other Taxes			
	Labor-Related Taxes	(Note E)	
[30]	Payroll	Internal Records	$ -
[31]	Highway and Vehicle	Internal Records	$ -
[32]	Wage and Salary Allocator	Table P2: [3]	
[33]	**Labor-Related Taxes Allocated to Transmission**	**([30] + [31]) x [32]**	**$ -**
	Plant-Related Taxes	(Note E)	
[34]	Property	Internal Records	$ -
[35]	Gross Reciepts	Internal Records	$ -
[36]	Other	Internal Records	$ -
[37]	Gross Plant Allocator - Transmission	Table P2: [9]	
[38]	**Plant-Related Taxes Allocated to Transmission**	**SUM([34]:[36]) x [37]**	**$ -**
	Surplus Payments to the City and Franchise Fees		
[39]	Surplus Payments to the City and Franchise Fees	Internal Records, (Note F)	$ -
[40]	Net Plant Allocator	Table P2: [17]	
[41]	**Surplus Payments and Franchise Fees Allocated to Transmission**	[39] x [40]	**$ -**
[42]	**TOTAL OTHER TAXES**	**[33] + [38] + [41]**	**$ -**

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THIS SHEET IS IN USE FOR THE PROJECTED RATE CALCULATION

Table P1

Table P1: Projected Annual Transmission Revenue Requirement

Line No.	Item	Source/Calculation	Projected for 2026
Revenue Requirement			
	Debt Service Coverage Allocation	(Note G)	
[43]	Total Debt Service	[15]	$ -
[44]	Required Cash for Debt Service Coverage	% of Debt Service	
[45]	Cash Available for Debt Service	[43] x [44]	$ -
[46]	Gross Plant Allocator - Transmission	Table P2: [9]	
[47]	**Debt Service Coverage Allocated to Transmission**	**[45] x [46]**	**$ -**
[48]	**TRANSMISSION REVENUE REQUIREMENT**	**[14] + [29] + [42] + [47]**	**$ -**
[49]	Revenue Credits	**Table E3: [16]**	$ -
[50]	**TRANSMISSION REVENUE REQUIREMENT NET OF REVENUE CREDITS**	**[48] - [49]**	**$ -**

Notes:

(A) EPRI Annual Membership Dues (within Account 930), All Regulatory Commission Expenses (Account 928), and non-safety related advertising (within Account 930). Source: TFR Backup, [WP2 O&M - A&G] tab

(B) Common expense includes operations and maintenance shared across Electric, Natural Gas, Water, and Wastewater Services that is allocated to transmission.

(C) Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting (within Account 928)

(D) Commercial Paper interest that can be directly assigned to Transmission operations. If commercial paper is issued on behalf of specific areas of operations then the interest expense incurred from the issuance of commercial paper for Transmission operations will be directly assigned to Transmission on this line.

(E) Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Formula Rate Template, since they are recovered elsewhere.

(F) CSU provides for surplus payments to the City in lieu of taxes, based on a fixed rate per kWh of electricity sales within the city. Franchise Fees are related to providing Electric Service to customers residing in other neighboring cities or municipalities.

(G) The utility must collect a percentage of Debt Service to meet its debt service coverage obligations.

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THIS SHEET IS IN USE FOR THE PROJECTED RATE CALCULATION

Table P2

Table P2: Allocators Based on Projections

For use in Revenue Requirement Calculation

Line No.	Item	Source/Calculation	Projected for 2026
	Labor		
[1]	Total Labor Expense	Internal Records	$ -
[2]	Transmission Labor Expense	Table E1: [D][31]	$ -
[3]	**Wage and Salary Allocator**	**[1] / [2]**	
	Plant		
[4]	Gross Plant in Service	Sum of: Table P4, [11]	$ -
[5]	Gross Transmission Plant	Table P4: [B][11]	$ -
[6]	General and Intangible Plant	Table P4: [D][11] + [E][11]	$ -
[7]	Wage and Salary Allocator	[3]	
[8]	General and Intangible Plant Allocated to Transmission	[6] x [7]	$ -
[9]	**Gross Plant Allocator - Transmission**	**([5] + [8])/[4]**	
[10]	Accumulated Depreciation	Sum of Table PD2, [18]	$ -
[11]	Net Plant	[4] - [10]	$ -
[12]	Transmission Accumulated Depreciation	Table PD2: [B][18]	$ -
[13]	General and Intangible Accumulated Depreciation	Table PD2: [D][18] + [E][18]	$ -
[14]	Wage and Salary Allocator	[3]	
[15]	General and Intangible Accumulated Depreciation Allocated to Transmission	[13] x [14]	$ -
[16]	Net Transmission Plant	[5] + [8] - [12] - [15]	$ -
[17]	**Net Plant Allocator**	**[16]/[11]**	
	Electric Capital		
[18]	Cash-Funded Capital Less CIAC and Adjustments	Table C1: [F][9]	$ -
[19]	Total Electric Capital Less Adjustments	Sum of Table C1: [A][9]:[D][9]	$ -
[20]	**Cash-Funded Capital Allocator**	**[18] / [19]**	

Notes:
[1] Total Labor Expense is the sum of Projected Year Budget from TFR Backup, [WP2 O&M - A&G] tab.

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THIS SHEET IS IN USE FOR THE PROJECTED RATE CALCULATION

Table P3

Table P3: True Up

Projected ATRR Only

Line No.	Item	Source/Calculation	Transmission	Base Plan Upgrades
[1]	Year for True-Up:		2024	2024
[2]	**Revenue**			
[3]	2024 Actual ATRR	Table T1: [50] or Table BP1: [3]	$ -	$ -
[4]	2024 Revenue Collected	Internal Records	$ -	$ -
[5]	**Undercollection / (Refund)**	[3] - [4]	$ -	$ -
[6]	**Prior Period Adjustment (if Necessary)**	Supplemental Workpaper	$ -	$ -
[7]	**True-Up Before Interest**	[5] + [6]	$ -	$ -
	Interest Rates			
[8]	First Quarter	FERC Posted Interest Rates		
[9]	Second Quaarter	FERC Posted Interest Rates		
[10]	Third Quarter	FERC Posted Interest Rates		
[11]	Fourth Quarter	FERC Posted Interest Rates		
[12]	**Average**	([8] + [9] + [10] + [11])/4	0.00%	0.00%
[13]	**True-Up Interest**	[6] x (([12]/12 months) x 24 months)	$ -	$ -
[14]	**Total True-Up**	[7] + [13]	$ -	$ -

Notes:

[4]: Collected on Formula Rate Submitted in 2023. Disclaimer: No Formula Rate was submitted in 2023. With 2026 anticipated to be the first year of implementing a formula rate, 2024 revenues collected are assumed to equal the 2024 Actual ATRR calculated in this workbook.

Prior Period Adjustment, if any, is calculated to the same timing basis as balance of true up (i.e. before interest applied on lines 15 and 22). Work-papers for the Prior Period Adjustment calculation will be included in supporting documentation. CSU will only use the Prior Period Adjustment in the following circumstances and only if the error discovered would have impacted CSU's calculation of the True-Up Amount in a prior Rate Year: (1) CSU discovers a error in a previously filed formula rate (filed outside the current Rate Year), (2) discovers an error in books and records actually used to populate an input in the formula rate and the discovery is outside the current Rate Year, or (3) CSU is required by applicable law, a court or regulatory body to correct an error outside the current Rate Year. If an error falls within one of these three categories and negatively impacted customers in CSU's calculation of a prior Rate Year’s True-Up Amount, CSU will re-calculate the True-Up Amount for affected years.

Colorado Springs Utilities
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THIS SHEET IS IN USE FOR THE PROJECTED RATE CALCULATION

Table P4

Table P4: Projected Plant Additions

Line No.	Month	Source/Calculation	Production Plant [A]	Transmission Plant [B]	Distribution Plant [C]	General Plant [D]	Intangible Plant [E]
[1]	Projected Additions		$ -	$ -	$ -	$ -	$ -
[2]	Adjustments						
[3]			$ -	$ -	$ -	$ -	$ -
[4]			$ -	$ -	$ -	$ -	$ -
[5]			$ -	$ -	$ -	$ -	$ -
[6]			$ -	$ -	$ -	$ -	$ -
[7]			$ -	$ -	$ -	$ -	$ -
[8]			$ -	$ -	$ -	$ -	$ -
[9]	**Total Adjusted Projected Additions**	**SUM([1]:[8])**	$ -	$ -	$ -	$ -	$ -
[10]	**December 2024 Gross Plant**	Table PD1: [18]	$ -	$ -	$ -	$ -	$ -
[11]	**2026 Average Gross Plant**	[10] + ([9] / 2)	$ -	$ -	$ -	$ -	$ -

Notes:
[11]: Average Gross Plant additions are calculated as half of projected additions assuming plant is placed in service evenly throughout the year.

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THIS SHEET IS IN USE FOR THE PROJECTED RATE CALCULATION

Table P5

Table P5: Projected Load

MW

Line No.	Month	Firm Network for Self [A]	Fountain Firm Network Service for Others [B]	Long-Term Firm Point to Point Reservations [C]	Other Long-Term Firm Service [D]	Short Term Firm Point to Point Reservation [E]	Transmission System Peak Load [F] SUM([A]:[E])	12-Month Coincident Peak Average [G] [F] - [E]
[1]	January	-	-	-	-	-	-	-
[2]	February	-	-	-	-	-	-	-
[3]	March	-	-	-	-	-	-	-
[4]	April	-	-	-	-	-	-	-
[5]	May	-	-	-	-	-	-	-
[6]	June	-	-	-	-	-	-	-
[7]	July	-	-	-	-	-	-	-
[8]	August	-	-	-	-	-	-	-
[9]	September	-	-	-	-	-	-	-
[10]	October	-	-	-	-	-	-	-
[11]	November	-	-	-	-	-	-	-
[12]	December	-	-	-	-	-	-	-
[13]	12-Month Total							-
[14]	12-Month CP Average							-
[15]	**12-Month CP Average (kW)**							**-**

Notes:
[G]: 12-month CP average includes all load with the exception of Short-Term Firm Point-to-Point load.
[13]: SUM([1]:[12]).
[14]: [13]/ 12.
[15]: [14] x 1000.

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Table PD1

Table PD1: Gross Plant

Line No.	Month	Production Plant [A]	Transmission Plant [B]	Distribution Plant [C]
[1]	Dec-23	$ -	$ -	$ -
[2]	Jan-24	$ -	$ -	$ -
[3]	Feb-24	$ -	$ -	$ -
[4]	Mar-24	$ -	$ -	$ -
[5]	Apr-24	$ -	$ -	$ -
[6]	May-24	$ -	$ -	$ -
[7]	Jun-24	$ -	$ -	$ -
[8]	Jul-24	$ -	$ -	$ -
[9]	Aug-24	$ -	$ -	$ -
[10]	Sep-24	$ -	$ -	$ -
[11]	Oct-24	$ -	$ -	$ -
[12]	Nov-24	$ -	$ -	$ -
[13]	Dec-24	$ -	$ -	$ -
[14]	**Average Balance**	$ -	$ -	$ -
[15]	13 Month Average: Plant not Included in Rate Base *(enter negative)*	$ -	$ -	$ -
[16]		$ -	$ -	$ -
[17]		$ -	$ -	$ -
[18]	**Average Rate Base Balance**	$ -	$ -	$ -

Source: CSU Electric Plant Asset Book Value Workbook, summarized in TFR Backup, [WP3 Elec Plant Summary] tab
Notes:

[15] 13-Month Average Gross Plant of plant not included in rate base is entered as the average over the December prior to the Actuals Rate Year and each month of the Actuals Rate Year

Colorado Springs Utilities
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Projections for Rate Year 2026

Table PD1

Table PD1: Gross Plant

Line No.	Month	General Plant [D]	Intangible Plant [E]
[1]	Dec-23	$ -	$ -
[2]	Jan-24	$ -	$ -
[3]	Feb-24	$ -	$ -
[4]	Mar-24	$ -	$ -
[5]	Apr-24	$ -	$ -
[6]	May-24	$ -	$ -
[7]	Jun-24	$ -	$ -
[8]	Jul-24	$ -	$ -
[9]	Aug-24	$ -	$ -
[10]	Sep-24	$ -	$ -
[11]	Oct-24	$ -	$ -
[12]	Nov-24	$ -	$ -
[13]	Dec-24	$ -	$ -
[14]	**Average Balance**	$ -	$ -
[15]	13 Month Average: Plant not Included in Rate Base *(enter negative)*	$ -	$ -
[16]		$ -	$ -
[17]		$ -	$ -
[18]	**Average Rate Base Balance**	$ -	$ -

Source: CSU Electric Plant Asset Book Value Workbook, summarized in TFR Backup, [WP3 Elec Plant Summary] tab
Notes:

[15] 13-Month Average Gross Plant of plant not included in rate base is entered as the average over the December prior to the Actuals Rate Year and each month of the Actuals Rate Year

Colorado Springs Utilities
Formula Rate Workbook
Projections for Rate Year 2026

Table PD2

Table PD2: Accumulated Depreciation

Line No.	Month	Production Plant [A]	Transmission Plant [B]	Distribution Plant [C]
[1]	Dec-23	$ -	$ -	$ -
[2]	Jan-24	$ -	$ -	$ -
[3]	Feb-24	$ -	$ -	$ -
[4]	Mar-24	$ -	$ -	$ -
[5]	Apr-24	$ -	$ -	$ -
[6]	May-24	$ -	$ -	$ -
[7]	Jun-24	$ -	$ -	$ -
[8]	Jul-24	$ -	$ -	$ -
[9]	Aug-24	$ -	$ -	$ -
[10]	Sep-24	$ -	$ -	$ -
[11]	Oct-24	$ -	$ -	$ -
[12]	Nov-24	$ -	$ -	$ -
[13]	Dec-24	$ -	$ -	$ -
[14]	**Average Balance**	$ -	$ -	$ -
[15]	13 Month Average: Plant not Included in Rate Base *(enter negative)*	$ -	$ -	$ -
[16]		$ -	$ -	$ -
[17]		$ -	$ -	$ -
[18]	**Average Rate Base Balance**	$ -	$ -	$ -

Source: CSU Electric Plant Asset Book Value Workbook, summarized in TFR Backup, [WP3 Elec Plant Summary] tab
Notes:

[15] 13-Month Average Accumulated Depreciation of plant not included in rate base is entered as the average over the December prior to the Actuals Rate Year and each month of the Actuals Rate Year

Colorado Springs Utilities
Formula Rate Workbook
Projections for Rate Year 2026

Table PD2

Table PD2: Accumulated Depreciation

Line No.	Month	General Plant [D]	Intangible Plant [E]
[1]	Dec-23	$ -	$ -
[2]	Jan-24	$ -	$ -
[3]	Feb-24	$ -	$ -
[4]	Mar-24	$ -	$ -
[5]	Apr-24	$ -	$ -
[6]	May-24	$ -	$ -
[7]	Jun-24	$ -	$ -
[8]	Jul-24	$ -	$ -
[9]	Aug-24	$ -	$ -
[10]	Sep-24	$ -	$ -
[11]	Oct-24	$ -	$ -
[12]	Nov-24	$ -	$ -
[13]	Dec-24	$ -	$ -
[14]	**Average Balance**	$ -	$ -
[15]	13 Month Average: Plant not Included in Rate Base *(enter negative)*	$ -	$ -
[16]		$ -	$ -
[17]		$ -	$ -
[18]	**Average Rate Base Balance**	$ -	$ -

Source: CSU Electric Plant Asset Book Value Workbook, summarized in TFR Backup, [WP3 Elec Plant Summary] tab
Notes:

[15] 13-Month Average Accumulated Depreciation of plant not included in rate base is entered as the average over the December prior to the Actuals Rate Year and each month of the Actuals Rate Year

Colorado Springs Utilities
Formula Rate Workbook
Projections for Rate Year 2026

THIS SHEET IS IN USE FOR THE TRUE-UP RATE CALCULATION USING ACTUALS

Table C1

Table C1: Electric Capital Summary

Line No.	Item	Source/Calculation	Production Plant [A]	Transmission Plant [B]	Distribution Plant [C]	General Plant [D]	Intangible Plant [E]	Cash-Funded Capital Less CIAC [F]
[1]	**Total Electric Capital**	Table C2	$ -	$ -	$ -	$ -	$ -	$ -
[2]	**Adjustments**							
[3]			$ -	$ -	$ -	$ -	$ -	$ -
[4]			$ -	$ -	$ -	$ -	$ -	$ -
[5]			$ -	$ -	$ -	$ -	$ -	$ -
[6]			$ -	$ -	$ -	$ -	$ -	$ -
[7]			$ -	$ -	$ -	$ -	$ -	$ -
[8]			$ -	$ -	$ -	$ -	$ -	$ -
[9]	**Total Adjusted Electric Capital**	**SUM([1]:[8])**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Notes: Adjustments to Total Electric Capital for exclusion of plant not recovered in rates and inclusion of shared assets from common plant.

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THIS SHEET IS IN USE FOR THE TRUE-UP RATE CALCULATION USING ACTUALS

Table C2

Table C2: Electric Capital Detail

Line No.	Project Name [A]	Electric Capital [B]	Assigned Function [C]
[1]		$ -	
[2]		$ -	
[3]		$ -	
[4]		$ -	
[5]		$ -	
[6]		$ -	
[7]		$ -	
[8]		$ -	
[9]		$ -	
[10]		$ -	
[11]	**Total Electric Capital by Project**	$ -	
[12]	Cash-Funded Electric Capital	$ -	Internal Records
[13]	Allocated Electric Capital	$ -	Internal Records

Sources and Notes: [12] Cash-Funded Electric Capital is sourced from Internal record and is allocated to Transmission and General Plant. [13] Allocated Electric Capital is sourced from internal records and allocated to General Plant in the Electric Capital Summary tab. TFR Backup, [WP11 Misc Support] tab contains extracts from internal systems for source support.

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Table C3

Table C3: Debt Service and Interest

Thousands ($000)

Line No.	Bond Issue [A]	Electric Percentage [B]	Total Principal [C]	Total Interest [D]	Electric Principal [E] [C] x [B]	Electric Interest [F] [D] x [B]	Total Electric Debt [G] [E] + [F]
[1]		0.0%	$ -	$ -	$ -	$ -	$ -
[2]		0.0%	$ -	$ -	$ -	$ -	$ -
[3]		0.0%	$ -	$ -	$ -	$ -	$ -
[4]		0.0%	$ -	$ -	$ -	$ -	$ -
[5]		0.0%	$ -	$ -	$ -	$ -	$ -
[6]		0.0%	$ -	$ -	$ -	$ -	$ -
[7]		0.0%	$ -	$ -	$ -	$ -	$ -
[8]		0.0%	$ -	$ -	$ -	$ -	$ -
[9]		0.0%	$ -	$ -	$ -	$ -	$ -
[10]		0.0%	$ -	$ -	$ -	$ -	$ -
[11]		0.0%	$ -	$ -	$ -	$ -	$ -
[12]		0.0%	$ -	$ -	$ -	$ -	$ -
[13]		0.0%	$ -	$ -	$ -	$ -	$ -
[14]		0.0%	$ -	$ -	$ -	$ -	$ -
[15]		0.0%	$ -	$ -	$ -	$ -	$ -
[16]		0.0%	$ -	$ -	$ -	$ -	$ -
[17]		0.0%	$ -	$ -	$ -	$ -	$ -
[18]		0.0%	$ -	$ -	$ -	$ -	$ -
[19]		0.0%	$ -	$ -	$ -	$ -	$ -
[20]		0.0%	$ -	$ -	$ -	$ -	$ -
[21]		0.0%	$ -	$ -	$ -	$ -	$ -
[22]		0.0%	$ -	$ -	$ -	$ -	$ -
[23]		0.0%	$ -	$ -	$ -	$ -	$ -

Colorado Springs Utilities
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Table C3

Table C3: Debt Service and Interest

Thousands ($000)

Line No.	Bond Issue [A]	Electric Percentage [B]	Total Principal [C]	Total Interest [D]	Electric Principal [E] [C] x [B]	Electric Interest [F] [D] x [B]	Total Electric Debt [G] [E] + [F]
[24]		0.0%	$ -	$ -	$ -	$ -	$ -
[25]		0.0%	$ -	$ -	$ -	$ -	$ -
[26]		0.0%	$ -	$ -	$ -	$ -	$ -
[27]		0.0%	$ -	$ -	$ -	$ -	$ -
[28]		0.0%	$ -	$ -	$ -	$ -	$ -
[29]		0.0%	$ -	$ -	$ -	$ -	$ -
[30]		0.0%	$ -	$ -	$ -	$ -	$ -
[31]		0.0%	$ -	$ -	$ -	$ -	$ -
[32]		0.0%	$ -	$ -	$ -	$ -	$ -
[33]		0.0%	$ -	$ -	$ -	$ -	$ -
[34]		0.0%	$ -	$ -	$ -	$ -	$ -
[35]		0.0%	$ -	$ -	$ -	$ -	$ -
[36]		0.0%	$ -	$ -	$ -	$ -	$ -
[37]		0.0%	$ -	$ -	$ -	$ -	$ -
[38]		0.0%	$ -	$ -	$ -	$ -	$ -
[39]		0.0%	$ -	$ -	$ -	$ -	$ -
[40]		0.0%	$ -	$ -	$ -	$ -	$ -
[41]		0.0%	$ -	$ -	$ -	$ -	$ -
[42]		0.0%	$ -	$ -	$ -	$ -	$ -
[43]		0.0%	$ -	$ -	$ -	$ -	$ -
[44]		0.0%	$ -	$ -	$ -	$ -	$ -
[45]		0.0%	$ -	$ -	$ -	$ -	$ -
[46]		0.0%	$ -	$ -	$ -	$ -	$ -

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Table C3

Table C3: Debt Service and Interest

Thousands ($000)

Line No.	**Bond Issue** [A]	**Electric Percentage** [B]	**Total Principal** [C]	**Total Interest** [D]	**Electric Principal** [E] [C] x [B]	**Electric Interest** [F] [D] x [B]	**Total Electric Debt** [G] [E] + [F]
[47]		0.0%	$ -	$ -	$ -	$ -	$ -
[48]		0.0%	$ -	$ -	$ -	$ -	$ -
[49]		0.0%	$ -	$ -	$ -	$ -	$ -
[50]		0.0%	$ -	$ -	$ -	$ -	$ -
[51]	Forecasted Debt		$ -	$ -	$ -	$ -	$ -
[52]	**Total**		$ -	$ -	$ -	$ -	$ -

Source: TFR Backup, [WP7 Debt Service and Interest] tab.

Table C4

Table C4: Amortization of Premium or Discount

Line No.	Fiscal Year [A]	Account Number [B]	Account Name [C]	Sub Account [D]	Sub Account Cost Type [E]	Balance Year-To-Date [F]
[1]						
[2]						
[3]						
[4]						
[5]						
[6]						
[7]						
[8]						
[9]						
[10]						
[11]						
[12]						
[13]						
[14]						
[15]						
[16]						
[17]						
[18]						
[19]						
[20]						
[21]						
[22]						
[23]						
[24]						
[25]						
[26]						
[27]						
[28]						
[29]						
[30]						

Table C4

Table C4: Amortization of Premium or Discount

Line No.	Fiscal Year [A]	Account Number [B]	Account Name [C]	Sub Account [D]	Sub Account Cost Type [E]	Balance Year-To-Date [F]
[31]						
[32]						
[33]						
[34]						
[35]						
[36]						
[37]						
[38]						
[39]						
[40]						
[41]						
[42]						
[43]						
[51]	**Total Amortization of Premium or Discount**					$ 0

Source: TFR Backup, [WP8 Amortization of prem or dis] & [WP9 Bond Issu Amort Exp Detail] tabs.

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Table E1

Table E1: Transmission Operations and Maintenance (O&M) Expenses

Line No.	Item	FERC Account No./Calculation	Actual Total [A]	Actual Labor-Related [B]
[1]	**Operation**			
[2]	Operation, Supervision and Engineering	560	$ -	$ -
[3]	Load Dispatching	561	$ -	$ -
[4]	Load Dispatch- Reliability	561.1	$ -	$ -
[5]	Load Dispatch- Monitor and Operate Transmission System	561.2	$ -	$ -
[6]	Load Dispatch- Transmission Service and Scheduling	561.3	$ -	$ -
[7]	Scheduling, System Control and Dispatch Services	561.4	$ -	$ -
[8]	Reliability, Planning and Standards Development	561.5	$ -	$ -
[9]	Transmission Service Studies	561.6	$ -	$ -
[10]	Generation Interconnection Studies	561.7	$ -	$ -
[11]	Reliability, Planning and Standards Development Services	561.8	$ -	$ -
[12]	Station Expenses	562	$ -	$ -
[13]	Overhead Line Expenses	563	$ -	$ -
[14]	Underground Line Expenses	564	$ -	$ -
[15]	Transmission of Electricity by Others	565	$ -	$ -
[16]	Miscellaneous Transmission Expenses	566	$ -	$ -
[17]	Rents	567	$ -	$ -
[18]	**Total Operation**		$ -	$ -

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Table E1

Table E1: Transmission Operations and Maintenance (O&M) Expenses

Line No.	Item	FERC Account No./Calculation	Actual Total [A]	Actual Labor-Related [B]
[19]	**Maintenance**			
[20]	Maintenance Supervision and Engineering	568	$ -	$ -
[21]	Maintenance of Structures	569	$ -	$ -
[22]	Maintenance of Computer Hardware	569.1	$ -	$ -
[23]	Maintenance of Computer Software	569.2	$ -	$ -
[24]	Maintenance of Communication Equipment	569.3	$ -	$ -
[25]	Maintenance of Miscellaneous Regional Transmission Plant	569.4	$ -	$ -
[26]	Maintenance of Station Equipment	570	$ -	$ -
[27]	Maintenance of Overhead Lines	571	$ -	$ -
[28]	Maintenance of Underground Lines	572	$ -	$ -
[29]	Maintenance of Miscellaneous Transmission Plant	573	$ -	$ -
[30]	**Total Maintenance**		$ -	$ -
[31]	**Total Operation and Maintenance Expense**	**[18] + [30]**	**$ -**	**$ -**

Source: TFR Backup, [WP2 O&M - A&G] tab.

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Table E1

Table E1: Transmission Operations and Maintenance (O&M) Expenses

Line No.	Item	FERC Account No./Calculation	Projected Total [C]	Projected Labor-Related [D]
[1]	**Operation**			
[2]	Operation, Supervision and Engineering	560	$ -	$ -
[3]	Load Dispatching	561	$ -	$ -
[4]	Load Dispatch- Reliability	561.1	$ -	$ -
[5]	Load Dispatch- Monitor and Operate Transmission System	561.2	$ -	$ -
[6]	Load Dispatch- Transmission Service and Scheduling	561.3	$ -	$ -
[7]	Scheduling, System Control and Dispatch Services	561.4	$ -	$ -
[8]	Reliability, Planning and Standards Development	561.5	$ -	$ -
[9]	Transmission Service Studies	561.6	$ -	$ -
[10]	Generation Interconnection Studies	561.7	$ -	$ -
[11]	Reliability, Planning and Standards Development Services	561.8	$ -	$ -
[12]	Station Expenses	562	$ -	$ -
[13]	Overhead Line Expenses	563	$ -	$ -
[14]	Underground Line Expenses	564	$ -	$ -
[15]	Transmission of Electricity by Others	565	$ -	$ -
[16]	Miscellaneous Transmission Expenses	566	$ -	$ -
[17]	Rents	567	$ -	$ -
[18]	**Total Operation**		$ -	$ -

Table E1

Table E1: Transmission Operations and Maintenance (O&M) Expenses

Line No.	Item	FERC Account No./Calculation	Projected Total [C]	Projected Labor-Related [D]
[19]	**Maintenance**			
[20]	Maintenance Supervision and Engineering	568	$ -	$ -
[21]	Maintenance of Structures	569	$ -	$ -
[22]	Maintenance of Computer Hardware	569.1	$ -	$ -
[23]	Maintenance of Computer Software	569.2	$ -	$ -
[24]	Maintenance of Communication Equipment	569.3	$ -	$ -
[25]	Maintenance of Miscellaneous Regional Transmission Plant	569.4	$ -	$ -
[26]	Maintenance of Station Equipment	570	$ -	$ -
[27]	Maintenance of Overhead Lines	571	$ -	$ -
[28]	Maintenance of Underground Lines	572	$ -	$ -
[29]	Maintenance of Miscellaneous Transmission Plant	573	$ -	$ -
[30]	**Total Maintenance**		$ -	$ -
[31]	**Total Operation and Maintenance Expense**	**[18] + [30]**	**$ -**	**$ -**

Source: TFR Backup, [WP2 O&M - A&G] tab.

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Table E2

Table E2: Administrative and General (A&G) Expenses

Line No.	Item	FERC Account No.	Actual Account Balance [A]	Projected Account Balance [B]
[1]	Administrative and General Salaries	920	$ -	$ -
[2]	Office Supplies and Expenses	921	$ -	$ -
[3]	Administrative Expenses Transferred-Credit (*enter negative*)	922	$ -	$ -
[4]	Outside Services Employed	923	$ -	$ -
[5]	Property Insurance	924	$ -	$ -
[6]	Injuries and Damage	925	$ -	$ -
[7]	Employee Pensions and Benefits	926	$ -	$ -
[8]	Franchise Requirements	927	$ -	$ -
[9]	Regulatory Commission Expenses	928	$ -	$ -
[10]	Duplicate Charges - Credit (*enter negative*)	929	$ -	$ -
[11]	General Advertising Expenses	930.1	$ -	$ -
[12]	Miscellaneous General Expenses	930.2	$ -	$ -
[13]	Rents	931	$ -	$ -
[14]	Maintenance of General Plant	932	$ -	$ -
[15]	**Total Administrative and General Expense**		$ -	$ -

Source: TFR Backup, [WP2 O&M - A&G] tab.

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Table E3

Table E3: Revenue Credits

Line No.	Item	Source/Calculation	FERC Account No.	Total Transmission
	Sales for Resale			
[1]	Bundled Non-RQ Sales for Resale		447	$ -
[2]	Bundled Sales for Resale included in Divisor		447	$ -
[3]	**Total Sales for Resale**	**[1] + [2]**		$ -
	Rent from Electric Property			
[4]			454	$ -
[5]			454	$ -
[6]			454	$ -
[7]			454	$ -
[8]			454	$ -
[9]			454	$ -
[10]			454	$ -
[11]			454	$ -
[12]			454	$ -
[13]			454	$ -
[14]	**Total Rent from Electric Property**	**SUM([4]:[13])**		$ -
[15]	**Other Electric Revenues Credited**	**Table E4: [15]**	456	$ -
[16]	**TOTAL REVENUE CREDITS**	**[3] + [14] + [15]**		$ -

Source: TFR Backup, [WP10 Account 456.1] tab.

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Table E4

Table E4: Other Electric Revenues

Line No.	Description	Assignment	Total Revenue
[1]			$ -
[2]			$ -
[3]			$ -
[4]			$ -
[5]			$ -
[6]			$ -
[7]			$ -
[8]			$ -
[9]			$ -
[10]			$ -
[11]			$ -
[12]			$ -
[13]			$ -
[14]			$ -
[15]	**TOTAL REVENUE CREDIT**		$ -

Source: TFR Backup, [WP10 Account 456.1] tab.

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Table TRC

Table TRC: Transmission Rate Calculation

Projections for Rate Year 2026

Line No.	Item	Unit	Source/Calculation	Actual for 2024	Projected for 2026
[1]	Transmission Revenue Requirement Net of Revenue Credits	$/year	Table T1 or Table P1: [50]	$ 50,814,334	$ 34,281,960
[2]	True-Up (if Applicable)	$/year	Table P3: [14]	n/a	$ 0
[3]	Schedule 11 Revenue incl. Schedule 11 True-Up	$/year	Table BP1: [3]	$ -	$ -
[4]	**Transmission Revenue Requirement Net of Schedule 11 Revenue**	**$/year**	**[1] + [2] - [3]**	**$ 50,814,334**	**$ 34,281,960**
[5]	Peak Transmission Load	kW	Table T3: [15] or Table P5: [15]	834,170	888,917
	Schedule 7: Long-Term Firm and Short-Term Point-to-Point Transmission Service				
	The charges are as follows:				
[6]	Yearly Delivery	$/kW-year	[4] / [5]	$ 60.92	$ 38.57
[7]	Monthly Delivery	$/kW-month	[6] / 12	$ 5.0763	$ 3.2138
[8]	Weekly Delivery	$/kW-week	[6] / 52	$ 1.1715	$ 0.7417
[9]	Daily On-Peak Delivery	$/kW-day	[6] / 270	$ 0.2256	$ 0.1428
[10]	Daily Off-Peak Delivery	$/kW-day	[6] / 365	$ 0.1669	$ 0.1057
[11]	Hourly On-Peak Delivery	$/kWh	[9] / 16	$ 0.0141	$ 0.0089
[12]	Hourly Off-Peak Delivery	$/kWh	[10] / 24	$ 0.0070	$ 0.0044
	Schedule 8: Non-Firm Point-to-Point Transmission Service				
	The charges can be up to the following limits:				
[13]	Monthly Delivery	$/kW-month	[6] / 12	$ 5.0763	$ 3.2138
[14]	Weekly Delivery	$/kW-week	[6] / 52	$ 1.1715	$ 0.7417
[15]	Daily On-Peak Delivery	$/kW-day	[6] / 270	$ 0.2256	$ 0.1428
[16]	Daily Off-Peak Delivery	$/kW-day	[6] / 365	$ 0.1669	$ 0.1057
[17]	Hourly On-Peak Delivery	$/kWh	[15] / 16	$ 0.0141	$ 0.0089
[18]	Hourly Off-Peak Delivery	$/kWh	[16] / 24	$ 0.0070	$ 0.0044
[19]	**Schedule 11: Base Plan Upgrades**	**$/year**	**[3]**	**$ -**	**$ -**

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PROJECTED ATRR IS IN USE FOR THE PROJECTED RATE CALCULATION

Table BP1

Table BP1: Base Plan Upgrade Annual Transmission Revenue Requirement

Line No.	Item	Source/Calculation	Actual for 2024	Projected for 2026
[1]	Total Base Plan Upgrade Costs	Table BP3: [21]	$ -	$ -
[2]	Base Plan Upgrades True Up (if Applicable)	Table P3: [14]		$ -
[3]	**BASE PLAN UPGRADES ATRR**	**[1] + [2]**	**$ -**	**$ -**

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PROJECTED ATRR IS IN USE FOR THE PROJECTED RATE CALCULATION

Table BP2

Table BP2: Fixed Charge Rate Calculation

Line No.	Item	Source/Calculation	Actual for 2024	Projected for 2026
[1]	ATRR Net of Revenue Credits	Table T1: [48] or Table P1: [48]	$ 50,814,334	$ 34,281,960
[2]	Net Transmission Plant	Table T2: [16] or Table P2: [16]	$ 93,791,154	$ 96,566,375
[3]	**Default Fixed Charge Rate**	**[1]/[2]**	**54.2%**	**35.5%**

Table BP3

Table BP3: Base Plan Upgrades Detail

Line No.	Project Name	Book Value in 2024	Book Value in 2026	Fixed Charge Rate for 2024	Fixed Charge Rate for 2026	To Actual ATRR for 2024	To Projected ATRR for 2026
[4]		$ -	$ -	54.2%	35.5%	$ -	$ -
[5]		$ -	$ -	54.2%	35.5%	$ -	$ -
[6]		$ -	$ -	54.2%	35.5%	$ -	$ -
[7]		$ -	$ -	54.2%	35.5%	$ -	$ -
[8]		$ -	$ -	54.2%	35.5%	$ -	$ -
[9]		$ -	$ -	54.2%	35.5%	$ -	$ -
[10]		$ -	$ -	54.2%	35.5%	$ -	$ -
[11]		$ -	$ -	54.2%	35.5%	$ -	$ -
[12]		$ -	$ -	54.2%	35.5%	$ -	$ -
[13]		$ -	$ -	54.2%	35.5%	$ -	$ -
[14]		$ -	$ -	54.2%	35.5%	$ -	$ -
[15]		$ -	$ -	54.2%	35.5%	$ -	$ -
[16]		$ -	$ -	54.2%	35.5%	$ -	$ -
[17]		$ -	$ -	54.2%	35.5%	$ -	$ -
[18]		$ -	$ -	54.2%	35.5%	$ -	$ -
[19]		$ -	$ -	54.2%	35.5%	$ -	$ -
[20]		$ -	$ -	54.2%	35.5%	$ -	$ -
[21]	**TOTAL BASE PLAN UPGRADES**					$ -	$ -

Notes:
Details on individual projects included in supplemental workpapers as needed.

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THIS SHEET IS IN USE FOR THE TRUE-UP RATE CALCULATION USING ACTUALS

Table T1

Table T1: 2024 Annual Transmission Revenue Requirement

Line No.	Item	Source/Calculation	Actual for 2024	
Operating Expenses				
	Operations and Maintenance			
[1]	Transmission O&M Expense	Table E1: [A][31]	$	6,655,735
[2]	Load Dispatch	Table E1: [A][3]	$	769,735
[3]	Transmission by Others	Table E1: [A][15]	$	-
[4]	**Transmission O&M Less Load Dispatch and Transmission by Others**	**[1] - [2] - [3]**	**$**	**5,886,000**
	Administrative and General			
[5]	Total A&G Expense	Table E2: [A][15]	$	74,972,938
[6]	(Less) FERC Annual Fees	Internal Records, (Note A)	$	-
[7]	(Less) EPRI & Regulatory Commission Exp. & Non-safety Ad	Internal Records, (Note A)	$	-
[8]	Wage and Salary Allocator	Table T2: [3]		10.4%
[9]	Total A&G Expense Allocated to Transmission	SUM([5]:[7]) x [8]	$	7,775,582
[10]	Transmission Related Regulatory Commission Expense	Internal Records (Note C)	$	-
[11]	**Administrative and General Expense**	**[9] + [10]**	**$**	**7,775,582**
[12]	Common O&M Expense Allocated to Transmission	Internal Records, (Note B)	$	-
[13]	Transmission Lease Payments	Internal Records	$	-
[14]	**TOTAL OPERATING EXPENSES**	**[4] + [11] + [12] + [13]**	**$**	**13,661,582**

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THIS SHEET IS IN USE FOR THE TRUE-UP RATE CALCULATION USING ACTUALS

Table T1

Table T1: 2024 Annual Transmission Revenue Requirement

Line No.	Item	Source/Calculation		Actual for 2024
Capital Projects				
	Debt Service			
[15]	Total Debt Service	Internal Records	$	85,551,954
[16]	Gross Plant Allocator - Transmission	Table T2: [9]		8.6%
[17]	**Total Debt Service Allocated to Transmission**	**[15] x [16]**	**$**	**7,340,806**
	Cash-Funded New Construction Assets			
[18]	Total Transmission Electric Capital	Table C1: [B][9]	$	65,364,327
[19]	Total General Electric Capital	Table C1: [D][9]	$	49,130,893
[20]	Gross Plant Allocator - Transmission	Table T2: [9]		8.6%
[21]	General Electric Capital Allocated to Transmission	[19] x [20]	$	4,215,688
[22]	Total Electric Capital Assigned and Allocated to Transmission	[18] + [21]	$	69,580,015
[23]	Cash-Funded Capital Allocator	Table T2: [20]		37.2%
[24]	**Total Cash-Funded New Construction Assets Allocated to Transmission**	[22] x [23]	$	25,874,269
	Amortization of Premium or Discount			
[25]	Amortization of Premium or Discount	Table C4: [F][51]	$	(6,274,637)
[26]	Gross Plant Allocator - Transmission	Table T2: [9]		8.6%
[27]	**Total Amortization of Premium or Discount Allocated to Transmission**	**[25] x [26]**	**$**	**(538,397)**
[28]	Interest on Commercial Paper Directly Assigned to Transmission	Internal Records, (Note D)	$	-
[29]	**TOTAL CAPITAL PROJECTS**	**[17] + [24] + [27] + [28]**	**$**	**32,676,679**

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THIS SHEET IS IN USE FOR THE TRUE-UP RATE CALCULATION USING ACTUALS

Table T1

Table T1: 2024 Annual Transmission Revenue Requirement

Line No.	Item	Source/Calculation		Actual for 2024
Other Taxes				
	Labor-Related Taxes	(Note E)		
[30]	Payroll	Internal Records	$	-
[31]	Highway and Vehicle	Internal Records	$	-
[32]	Wage and Salary Allocator	Table T2: [3]		10.37%
[33]	**Labor-Related Taxes Allocated to Transmission**	**([30] + [31]) x [32]**	**$**	**-**
	Plant-Related Taxes	(Note E)		
[34]	Property	Internal Records	$	-
[35]	Gross Reciepts	Internal Records	$	-
[36]	Other	Internal Records	$	-
[37]	Gross Plant Allocator - Transmission	Table T2: [9]		8.58%
[38]	**Plant-Related Taxes Allocated to Transmission**	**SUM([34]:[36]) x [37]**	**$**	**-**
	Surplus Payments to the City and Franchise Fees			
[39]	Surplus Payments to the City and Franchise Fees	Internal Records, (Note F)	$	25,349,433
[40]	Net Plant Allocator	Table T2: [17]		9.0%
[41]	**Surplus Payments and Franchise Fees Allocated to Transmission**	[39] x [40]	**$**	**2,273,831**
[42]	**TOTAL OTHER TAXES**	**[33] + [38] + [41]**	**$**	**2,273,831**

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THIS SHEET IS IN USE FOR THE TRUE-UP RATE CALCULATION USING ACTUALS

Table T1

Table T1: 2024 Annual Transmission Revenue Requirement

Line No.	Item	Source/Calculation		Actual for 2024
Revenue Requirement				
	Debt Service Coverage Allocation	(Note G)		
[43]	Total Debt Service	[15]	$	85,551,954
[44]	Required Cash for Debt Service Coverage	% of Debt Service		30%
[45]	Cash Available for Debt Service	[43] x [44]	$	25,665,586
[46]	Gross Plant Allocator - Transmission	Table T2: [9]		8.6%
[47]	**Debt Service Coverage Allocated to Transmission**	**[45] x [46]**	**$**	**2,202,242**
[48]	**TRANSMISSION REVENUE REQUIREMENT**	**[14] + [29] + [42] + [47]**	**$**	**50,814,334**
[49]	Revenue Credits	**Table E3: [16]**	$	-
[50]	**TRANSMISSION REVENUE REQUIREMENT NET OF REVENUE CREDITS**	**[48] - [49]**	**$**	**50,814,334**

Notes:

(A) EPRI Annual Membership Dues (within Account 930), All Regulatory Commission Expenses (Account 928), and non-safety related advertising (within Account 930). Source: TFR Backup, [WP2 O&M - A&G] tab

(B) Common expense includes operations and maintenance shared across Electric, Natural Gas, Water, and Wastewater Services that is allocated to transmission.

(C) Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting (within Account 928)

(D) Commercial Paper interest that can be directly assigned to Transmission operations. If commercial paper is issued on behalf of specific areas of operations then the interest expense incurred from the issuance of commercial paper for Transmission operations will be directly assigned to Transmission on this line.

(E) Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Formula Rate Template, since they are recovered elsewhere.

(F) CSU provides for surplus payments to the City in lieu of taxes, based on a fixed rate per kWh of electricity sales within the city. Franchise Fees are related to providing Electric Service to customers residing in other neighboring cities or municipalities.

(G) The utility must collect a percentage of Debt Service to meet its debt service coverage obligations.

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THIS SHEET IS IN USE FOR THE TRUE-UP RATE CALCULATION USING ACTUALS

Table T2

Table T2: Allocators Based on Actuals

For use in Revenue Requirement Calculation

Line No.	Item	Source/Calculation	Actual for 2024
	Labor		
[1]	Total Labor Expense	Internal Records	$ 56,214,252
[2]	Transmission Labor Expense	Table E1: [B][31]	$ 5,830,084
[3]	**Wage and Salary Allocator**	**[1] / [2]**	**10.37%**
	Plant		
[4]	Gross Plant in Service	Sum of: Table PD1, [18]	$ 2,586,365,838
[5]	Gross Transmission Plant	Table PD1: [B][18]	$ 204,880,933
[6]	General Plant	Table PD1: [D][18] + [E][18]	$ 164,328,527
[7]	Wage and Salary Allocator	[3]	10.37%
[8]	General Plant Allocated to Transmission	[6] x [7]	$ 17,042,816
[9]	**Gross Plant Allocator - Transmission**	**([5] + [8])/[4]**	**8.58%**
[10]	Accumulated Depreciation	Sum of Table PD2, [18]	$ 1,540,750,617
[11]	Net Plant	[4] - [10]	$ 1,045,615,221
[12]	Transmission Accumulated Depreciation	Table PD2: [B][18]	$ 117,452,418
[13]	General Plant Accumulated Depreciation	Table PD2: [D][18] + [E][18]	$ 102,979,329
[14]	Wage and Salary Allocator	[3]	10.37%
[15]	General Accumulated Depreciation Allocated to Transmission	[13] x [14]	$ 10,680,177
[16]	Net Transmission Plant	[5] + [8] - [12] - [15]	$ 93,791,154
[17]	**Net Plant Allocator**	**[16] / [11]**	**8.97%**
	Electric Capital		
[18]	Cash-Funded Capital Less CIAC and Adjustments	Table C1: [F][9]	$ 76,512,765
[19]	Total Electric Capital Less Adjustments	Sum of Table C1: [A][9]:[D][9]	$ 205,754,964
[20]	**Cash-Funded Capital Allocator**	**[18] / [19]**	**37.19%**

Notes:
[1] Total Labor Expense is the sum of Actual Year Budget from TFR Backup, [WP2 O&M - A&G] tab.

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THIS SHEET IS IN USE FOR THE TRUE-UP RATE CALCULATION USING ACTUALS

Table T3

Table T3: Load Divisor

MW

Line No.	Month [A]	Firm Network for Self [B]	Fountain Firm Network Service for Others [C]	Long-Term Firm Point to Point Reservations [D]	Other Long-Term Firm Service [E]	Short Term Firm Point to Point Reservation [F]	Transmission System Peak Load [G] SUM([B]:[F])	12-Month Coincident Peak Average [H] [G] - [F]
[1]	January	844	43	-	-	40	927	887
[2]	February	685	34	-	-	-	719	719
[3]	March	663	32	-	-	10	706	696
[4]	April	618	30	-	-	-	649	649
[5]	May	658	39	-	-	-	697	697
[6]	June	978	60	-	-	23	1,062	1,039
[7]	July	1,011	65	-	-	24	1,099	1,075
[8]	August	993	64	-	-	27	1,084	1,057
[9]	September	834	51	-	-	20	905	885
[10]	October	752	47	-	-	-	799	799
[11]	November	705	33	-	-	-	738	738
[12]	December	733	38	-	-	-	771	771
[13]	12-Month Total							10,010
[14]	12-Month CP Average							834
[15]	**12-Month CP Average (kW)**							**834,170**

Notes:
[H]: 12-month CP average includes all load with the exception of Short-Term Firm Point-to-Point load.
[13]: SUM([1]:[12]).
[14]: [13]/ 12.
[15]: [14] x 1000.

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THIS SHEET IS IN USE FOR THE PROJECTED RATE CALCULATION

Table P1

Table P1: Projected Annual Transmission Revenue Requirement

Line No.	Item	Source/Calculation		Projected for 2026
Operating Expenses				
	Operations and Maintenance			
[1]	Transmission O&M Expense	Table E1: [C][31]	$	9,646,593
[2]	Load Dispatch	Table E1: [C][3]	$	2,255,582
[3]	Transmission by Others	Table E1: [C][15]	$	-
[4]	**Transmission O&M Less Load Dispatch and Transmission by Others**	**[1] - [2] - [3]**	**$**	**7,391,011**
	Administrative and General			
[5]	Total A&G Expense	Table E2: [B][15]	$	84,847,133
[6]	(Less) FERC Annual Fees	Internal Records, (Note A)	$	-
[7]	(Less) EPRI & Regulatory Commission Exp. & Non-safety Ad	Internal Records, (Note A)	$	-
[8]	Wage and Salary Allocator	Table P2: [3]		11.5%
[9]	Total A&G Expense Allocated to Transmission	SUM([5]:[7]) x [8]	$	9,761,229
[10]	Transmission Related Regulatory Commission Expense	Internal Records (Note C)	$	-
[11]	**Administrative and General Expense**	**[9] + [10]**	**$**	**9,761,229**
[12]	Common O&M Expense Allocated to Transmission	Internal Records, (Note B)	$	-
[13]	Transmission Lease Payments	Internal Records	$	-
[14]	**TOTAL OPERATING EXPENSES**	**[4] + [11] + [12] + [13]**	**$**	**17,152,240**

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THIS SHEET IS IN USE FOR THE PROJECTED RATE CALCULATION

Table P1

Table P1: Projected Annual Transmission Revenue Requirement

Line No.	Item	Source/Calculation		Projected for 2026
Capital Projects				
	Debt Service			
[15]	Total Debt Service	Table C3: [G][52] x 1000	$	125,372,167
[16]	Gross Plant Allocator - Transmission	Table P2: [9]		8.5%
[17]	**Total Debt Service Allocated to Transmission**	**[15] x [16]**	**$**	**10,711,016**
	Cash-Funded New Construction Assets			
[18]	Projected Transmission Capital Additions	Table P4: [B][9]	$	2,270,703
[19]	Projected General Capital Additions	Table P4: [D][9]	$	16,421,360
[20]	Gross Plant Allocator - Transmission	Table P2: [9]		8.5%
[21]	General Electric Capital Allocated to Transmission	[19] x [20]	$	1,402,939
[22]	Total Electric Capital Assigned and Allocated to Transmission	[18] + [21]	$	3,673,642
[23]	Cash-Funded Capital Allocator	Table P2: [20]		37.2%
[24]	**Total Cash-Funded New Construction Assets Allocated to Transmission**	**[22] x [23]**	**$**	**1,366,093**
	Amortization of Premium or Discount			
[25]	Amortization of Premium or Discount	Table C4: [F][51]	$	(6,274,637)
[26]	Gross Plant Allocator - Transmission	Table P2: [9]		8.5%
[27]	**Total Amortization of Premium or Discount Allocated to Transmission**	**[25] x [26]**	**$**	**(536,066)**
[28]	Interest on Commercial Paper Directly Assigned to Transmission	Internal Records, (Note D)	$	-
[29]	**TOTAL CAPITAL PROJECTS**	**[17] + [24] + [27] + [28]**	**$**	**11,541,044**

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THIS SHEET IS IN USE FOR THE PROJECTED RATE CALCULATION

Table P1

Table P1: Projected Annual Transmission Revenue Requirement

Line No.	Item	Source/Calculation	Projected for 2026
Other Taxes			
	Labor-Related Taxes	(Note E)	
[30]	Payroll	Internal Records	$ -
[31]	Highway and Vehicle	Internal Records	$ -
[32]	Wage and Salary Allocator	Table P2: [3]	11.5%
[33]	**Labor-Related Taxes Allocated to Transmission**	**([30] + [31]) x [32]**	**$ -**
	Plant-Related Taxes	(Note E)	
[34]	Property	Internal Records	$ -
[35]	Gross Reciepts	Internal Records	$ -
[36]	Other	Internal Records	$ -
[37]	Gross Plant Allocator - Transmission	Table P2: [9]	8.5%
[38]	**Plant-Related Taxes Allocated to Transmission**	**SUM([34]:[36]) x [37]**	**$ -**
	Surplus Payments to the City and Franchise Fees		
[39]	Surplus Payments to the City and Franchise Fees	Internal Records, (Note F)	$ 27,132,089
[40]	Net Plant Allocator	Table P2: [17]	8.8%
[41]	**Surplus Payments and Franchise Fees Allocated to Transmission**	[39] x [40]	**$ 2,375,371**
[42]	**TOTAL OTHER TAXES**	**[33] + [38] + [41]**	**$ 2,375,371**

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THIS SHEET IS IN USE FOR THE PROJECTED RATE CALCULATION

Table P1

Table P1: Projected Annual Transmission Revenue Requirement

Line No.	Item	Source/Calculation		Projected for 2026
Revenue Requirement				
	Debt Service Coverage Allocation	(Note G)		
[43]	Total Debt Service	[15]	$	125,372,167
[44]	Required Cash for Debt Service Coverage	% of Debt Service		30%
[45]	Cash Available for Debt Service	[43] x [44]	$	37,611,650
[46]	Gross Plant Allocator - Transmission	Table P2: [9]		8.5%
[47]	**Debt Service Coverage Allocated to Transmission**	**[45] x [46]**	**$**	**3,213,305**
[48]	**TRANSMISSION REVENUE REQUIREMENT**	**[14] + [29] + [42] + [47]**	**$**	**34,281,960**
[49]	Revenue Credits	**Table E3: [16]**	$	-
[50]	**TRANSMISSION REVENUE REQUIREMENT NET OF REVENUE CREDITS**	**[48] - [49]**	**$**	**34,281,960**

Notes:

(A) EPRI Annual Membership Dues (within Account 930), All Regulatory Commission Expenses (Account 928), and non-safety related advertising (within Account 930). Source: TFR Backup, [WP2 O&M - A&G] tab

(B) Common expense includes operations and maintenance shared across Electric, Natural Gas, Water, and Wastewater Services that is allocated to transmission.

(C) Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting (within Account 928)

(D) Commercial Paper interest that can be directly assigned to Transmission operations. If commercial paper is issued on behalf of specific areas of operations then the interest expense incurred from the issuance of commercial paper for Transmission operations will be directly assigned to Transmission on this line.

(E) Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Formula Rate Template, since they are recovered elsewhere.

(F) CSU provides for surplus payments to the City in lieu of taxes, based on a fixed rate per kWh of electricity sales within the city. Franchise Fees are related to providing Electric Service to customers residing in other neighboring cities or municipalities.

(G) The utility must collect a percentage of Debt Service to meet its debt service coverage obligations.

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THIS SHEET IS IN USE FOR THE PROJECTED RATE CALCULATION

Table P2

Table P2: Allocators Based on Projections

For use in Revenue Requirement Calculation

Line No.	Item	Source/Calculation	Projected for 2026
	Labor		
[1]	Total Labor Expense	Internal Records	$ 63,336,555
[2]	Transmission Labor Expense	Table E1: [D][31]	$ 7,286,547
[3]	**Wage and Salary Allocator**	**[1] / [2]**	**11.50%**
	Plant		
[4]	Gross Plant in Service	Sum of: Table P4, [11]	$ 2,643,756,154
[5]	Gross Transmission Plant	Table P4: [B][11]	$ 206,016,285
[6]	General and Intangible Plant	Table P4: [D][11] + [E][11]	$ 172,539,207
[7]	Wage and Salary Allocator	[3]	11.5%
[8]	General and Intangible Plant Allocated to Transmission	[6] x [7]	$ 19,849,754
[9]	**Gross Plant Allocator - Transmission**	**([5] + [8])/[4]**	**8.54%**
[10]	Accumulated Depreciation	Sum of Table PD2, [18]	$ 1,540,750,617
[11]	Net Plant	[4] - [10]	$ 1,103,005,537
[12]	Transmission Accumulated Depreciation	Table PD2: [B][18]	$ 117,452,418
[13]	General and Intangible Accumulated Depreciation	Table PD2: [D][18] + [E][18]	$ 102,979,329
[14]	Wage and Salary Allocator	[3]	11.5%
[15]	General and Intangible Accumulated Depreciation Allocated to Transmission	[13] x [14]	$ 11,847,246
[16]	Net Transmission Plant	[5] + [8] - [12] - [15]	$ 96,566,375
[17]	**Net Plant Allocator**	**[16]/[11]**	**8.75%**
	Electric Capital		
[18]	Cash-Funded Capital Less CIAC and Adjustments	Table C1: [F][9]	$ 76,512,765
[19]	Total Electric Capital Less Adjustments	Sum of Table C1: [A][9]:[D][9]	$ 205,754,964
[20]	**Cash-Funded Capital Allocator**	**[18] / [19]**	**37.19%**

Notes:
[1] Total Labor Expense is the sum of Projected Year Budget from TFR Backup, [WP2 O&M - A&G] tab.

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THIS SHEET IS IN USE FOR THE PROJECTED RATE CALCULATION

Table P3

Table P3: True Up

Projected ATRR Only

Line No.	Item	Source/Calculation	Transmission	Base Plan Upgrades
[1]	Year for True-Up:		2024	2024
[2]	**Revenue**			
[3]	2024 Actual ATRR	Table T1: [50] or Table BP1: [3]	$ 50,814,334	$ -
[4]	2024 Revenue Collected	Internal Records	$ 50,814,334	$ -
[5]	**Undercollection / (Refund)**	[3] - [4]	$ 0	$ -
[6]	**Prior Period Adjustment (if Necessary)**	Supplemental Workpaper	$ -	$ -
[7]	**True-Up Before Interest**	[5] + [6]	$ 0	$ -
	Interest Rates			
[8]	First Quarter	FERC Posted Interest Rates	8.50%	
[9]	Second Quaarter	FERC Posted Interest Rates	8.50%	
[10]	Third Quarter	FERC Posted Interest Rates	8.04%	
[11]	Fourth Quarter	FERC Posted Interest Rates	7.55%	
[12]	**Average**	([8] + [9] + [10] + [11])/4	8.15%	8.15%
[13]	**True-Up Interest**	[6] x (([12]/12 months) x 24 months)	$ 0	$ -
[14]	**Total True-Up**	[7] + [13]	$ 0	$ -

Notes:

[4]: Collected on Formula Rate Submitted in 2023. Disclaimer: No Formula Rate was submitted in 2023. With 2026 anticipated to be the first year of implementing a formula rate, 2024 revenues collected are assumed to equal the 2024 Actual ATRR calculated in this workbook.

Prior Period Adjustment, if any, is calculated to the same timing basis as balance of true up (i.e. before interest applied on lines 15 and 22). Work-papers for the Prior Period Adjustment calculation will be included in supporting documentation. CSU will only use the Prior Period Adjustment in the following circumstances and only if the error discovered would have impacted CSU's calculation of the True-Up Amount in a prior Rate Year: (1) CSU discovers a error in a previously filed formula rate (filed outside the current Rate Year), (2) discovers an error in books and records actually used to populate an input in the formula rate and the discovery is outside the current Rate Year, or (3) CSU is required by applicable law, a court or regulatory body to correct an error outside the current Rate Year. If an error falls within one of these three categories and negatively impacted customers in CSU's calculation of a prior Rate Year’s True-Up Amount, CSU will re-calculate the True-Up Amount for affected years.

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THIS SHEET IS IN USE FOR THE PROJECTED RATE CALCULATION

Table P4

Table P4: Projected Plant Additions

Line No.	Month	Source/Calculation	Production Plant [A]	Transmission Plant [B]	Distribution Plant [C]	General Plant [D]	Intangible Plant [E]
[1]	Projected Additions	Internal Records	$ 65,830,494	$ 2,270,703	$ 30,258,075	$ 86,055,794	$ -
[2]	Adjustments						
[3]	193952 - Operational Fiber Network	Internal Records	$ -	$ -	$ -	$ (77,823,614)	$ -
[4]	Allocated Electric Capital	Internal Records	$ -	$ -	$ -	$ 8,189,180	$ -
[5]			$ -	$ -	$ -	$ -	$ -
[6]			$ -	$ -	$ -	$ -	$ -
[7]			$ -	$ -	$ -	$ -	$ -
[8]			$ -	$ -	$ -	$ -	$ -
[9]	**Total Adjusted Projected Additions**	**SUM([1]:[8])**	$ 65,830,494	$ 2,270,703	$ 30,258,075	$ 16,421,360	$ -
[10]	**December 2024 Gross Plant**	Table PD1: [18]	$ 922,017,956	$ 204,880,933	$ 1,295,138,422	$ 164,328,527	$ -
[11]	**2026 Average Gross Plant**	[10] + ([9] / 2)	$ 954,933,203	$ 206,016,285	$ 1,310,267,459	$ 172,539,207	$ -

Notes:
[11]: Average Gross Plant additions are calculated as half of projected additions assuming plant is placed in service evenly throughout the year.

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THIS SHEET IS IN USE FOR THE PROJECTED RATE CALCULATION

Table P5

Table P5: Projected Load

MW

Line No.	Month	Firm Network for Self [A]	Fountain Firm Network Service for Others [B]	Long-Term Firm Point to Point Reservations [C]	Other Long-Term Firm Service [D]	Short Term Firm Point to Point Reservation [E]	Transmission System Peak Load [F] SUM([A]:[E])	12-Month Coincident Peak Average [G] [F] - [E]
[1]	January	894	46	-	-	-	940	940
[2]	February	767	39	-	-	-	806	806
[3]	March	744	38	-	-	-	782	782
[4]	April	699	36	-	-	-	735	735
[5]	May	729	38	-	-	-	767	767
[6]	June	1,037	61	-	-	-	1,098	1,098
[7]	July	1,096	65	-	-	-	1,161	1,161
[8]	August	1,059	63	-	-	-	1,122	1,122
[9]	September	899	53	-	-	-	952	952
[10]	October	668	34	-	-	-	702	702
[11]	November	742	38	-	-	-	780	780
[12]	December	782	40	-	-	-	822	822
[13]	12-Month Total							10,667
[14]	12-Month CP Average							889
[15]	**12-Month CP Average (kW)**							**888,917**

Notes:
[G]: 12-month CP average includes all load with the exception of Short-Term Firm Point-to-Point load.
[13]: SUM([1]:[12]).
[14]: [13]/ 12.
[15]: [14] x 1000.

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Table PD1

Table PD1: Gross Plant

Line No.	Month	Production Plant [A]	Transmission Plant [B]	Distribution Plant [C]
[1]	Dec-23	$ 919,118,601	$ 193,622,468	$ 1,285,343,980
[2]	Jan-24	$ 919,118,601	$ 193,622,468	$ 1,285,343,980
[3]	Feb-24	$ 919,118,601	$ 193,622,468	$ 1,285,343,980
[4]	Mar-24	$ 919,118,601	$ 193,622,468	$ 1,285,343,980
[5]	Apr-24	$ 919,118,601	$ 193,622,468	$ 1,285,343,980
[6]	May-24	$ 919,120,339	$ 193,622,468	$ 1,285,874,066
[7]	Jun-24	$ 919,120,339	$ 196,326,482	$ 1,287,721,282
[8]	Jul-24	$ 919,120,339	$ 196,326,482	$ 1,287,721,282
[9]	Aug-24	$ 919,120,339	$ 196,326,482	$ 1,287,721,282
[10]	Sep-24	$ 919,120,339	$ 196,326,482	$ 1,287,721,282
[11]	Oct-24	$ 928,605,799	$ 201,416,697	$ 1,306,154,063
[12]	Nov-24	$ 931,332,799	$ 256,007,897	$ 1,306,544,129
[13]	Dec-24	$ 935,100,132	$ 258,986,795	$ 1,360,622,194
[14]	**Average Balance**	$ 922,017,956	$ 204,880,933	$ 1,295,138,422
[15]	13 Month Average: Plant not Included in Rate Base *(enter negative)*	$ -	$ -	$ -
[16]		$ -	$ -	$ -
[17]		$ -	$ -	$ -
[18]	**Average Rate Base Balance**	$ 922,017,956	$ 204,880,933	$ 1,295,138,422

Source: CSU Electric Plant Asset Book Value Workbook, summarized in TFR Backup, [WP3 Elec Plant Summary] tab
Notes:

[15] 13-Month Average Gross Plant of plant not included in rate base is entered as the average over the December prior to the Actuals Rate Year and each month of the Actuals Rate Year

Colorado Springs Utilities
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Projections for Rate Year 2026

Table PD1

Table PD1: Gross Plant

Line No.	Month	General Plant [D]	Intangible Plant [E]
[1]	Dec-23	$ 161,227,902	$ -
[2]	Jan-24	$ 161,227,902	$ -
[3]	Feb-24	$ 161,169,863	$ -
[4]	Mar-24	$ 161,744,051	$ -
[5]	Apr-24	$ 161,681,566	$ -
[6]	May-24	$ 161,182,189	$ -
[7]	Jun-24	$ 162,306,706	$ -
[8]	Jul-24	$ 159,658,355	$ -
[9]	Aug-24	$ 159,633,595	$ -
[10]	Sep-24	$ 159,592,684	$ -
[11]	Oct-24	$ 161,232,635	$ -
[12]	Nov-24	$ 162,108,363	$ -
[13]	Dec-24	$ 203,505,042	$ -
[14]	**Average Balance**	$ 164,328,527	$ -
[15]	13 Month Average: Plant not Included in Rate Base *(enter negative)*	$ -	$ -
[16]		$ -	$ -
[17]		$ -	$ -
[18]	**Average Rate Base Balance**	$ 164,328,527	$ -

Source: CSU Electric Plant Asset Book Value Workbook, summarized in TFR Backup, [WP3 Elec Plant Summary] tab
Notes:

[15] 13-Month Average Gross Plant of plant not included in rate base is entered as the average over the December prior to the Actuals Rate Year and each month of the Actuals Rate Year

Colorado Springs Utilities
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Projections for Rate Year 2026

Table PD2

Table PD2: Accumulated Depreciation

Line No.	Month	Production Plant [A]	Transmission Plant [B]	Distribution Plant [C]
[1]	Dec-23	$ 520,431,632	$ 115,023,017	$ 760,162,249
[2]	Jan-24	$ 524,041,838	$ 115,392,758	$ 763,159,824
[3]	Feb-24	$ 527,652,042	$ 115,762,499	$ 766,157,397
[4]	Mar-24	$ 531,262,250	$ 116,132,241	$ 769,154,974
[5]	Apr-24	$ 534,871,676	$ 116,501,982	$ 772,152,545
[6]	May-24	$ 538,481,144	$ 116,871,725	$ 775,162,717
[7]	Jun-24	$ 542,101,341	$ 117,345,198	$ 778,199,780
[8]	Jul-24	$ 545,696,052	$ 117,707,450	$ 781,135,741
[9]	Aug-24	$ 549,290,075	$ 118,069,702	$ 784,071,703
[10]	Sep-24	$ 552,883,155	$ 118,431,954	$ 787,007,664
[11]	Oct-24	$ 556,846,673	$ 118,885,893	$ 790,299,098
[12]	Nov-24	$ 560,635,597	$ 120,103,397	$ 793,290,136
[13]	Dec-24	$ 563,705,928	$ 120,653,614	$ 796,292,085
[14]	**Average Balance**	$ 542,146,108	$ 117,452,418	$ 778,172,763
[15]	13 Month Average: Plant not Included in Rate Base *(enter negative)*	$ -	$ -	$ -
[16]		$ -	$ -	$ -
[17]		$ -	$ -	$ -
[18]	**Average Rate Base Balance**	$ 542,146,108	$ 117,452,418	$ 778,172,763

Source: CSU Electric Plant Asset Book Value Workbook, summarized in TFR Backup, [WP3 Elec Plant Summary] tab

Notes:

[15] 13-Month Average Accumulated Depreciation of plant not included in rate base is entered as the average over the December prior to the Actuals Rate Year and each month of the Actuals Rate Year

Colorado Springs Utilities
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Table PD2

Table PD2: Accumulated Depreciation

Line No.	Month		General Plant [D]		Intangible Plant [E]
[1]	Dec-23	$	101,336,805	$	-
[2]	Jan-24	$	101,901,295	$	-
[3]	Feb-24	$	102,396,983	$	-
[4]	Mar-24	$	102,936,715	$	-
[5]	Apr-24	$	103,423,182	$	-
[6]	May-24	$	103,471,921	$	-
[7]	Jun-24	$	104,024,950	$	-
[8]	Jul-24	$	101,942,505	$	-
[9]	Aug-24	$	102,483,535	$	-
[10]	Sep-24	$	102,998,663	$	-
[11]	Oct-24	$	103,365,464	$	-
[12]	Nov-24	$	103,985,199	$	-
[13]	Dec-24	$	104,464,060	$	-
[14]	**Average Balance**	$	102,979,329	$	-
[15]	13 Month Average: Plant not Included in Rate Base *(enter negative)*	$	-	$	-
[16]		$	-	$	-
[17]		$	-	$	-
[18]	**Average Rate Base Balance**	$	102,979,329	$	-

Source: CSU Electric Plant Asset Book Value Workbook, summarized in TFR Backup, [WP3 Elec Plant Summary] tab
Notes:

[15] 13-Month Average Accumulated Depreciation of plant not included in rate base is entered as the average over the December prior to the Actuals Rate Year and each month of the Actuals Rate Year

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THIS SHEET IS IN USE FOR THE TRUE-UP RATE CALCULATION USING ACTUALS

Table C1

Table C1: Electric Capital Summary

Line No.	Item	Source/Calculation	Production Plant [A]	Transmission Plant [B]	Distribution Plant [C]	General Plant [D]	Intangible Plant [E]	Cash-Funded Capital Less CIAC [F]
[1]	**Total Electric Capital**	Table C2	$ 15,981,531	$ 65,364,327	$ 75,278,214	$ 82,866,640	$ -	$ 117,102,264
[2]	**Adjustments**							
[3]	193952 - Operational Fiber Network	Table C2	$ -	$ -	$ -	$ (40,589,499)	$ -	$ (40,589,499)
[4]	Allocated Electric Capital	Internal Records	$ -	$ -	$ -	$ 6,853,752	$ -	$ -
[5]			$ -	$ -	$ -	$ -	$ -	$ -
[6]			$ -	$ -	$ -	$ -	$ -	$ -
[7]			$ -	$ -	$ -	$ -	$ -	$ -
[8]			$ -	$ -	$ -	$ -	$ -	$ -
[9]	**Total Adjusted Electric Capital**	**SUM([1]:[8])**	**$ 15,981,531**	**$ 65,364,327**	**$ 75,278,214**	**$ 49,130,893**	**$ -**	**$ 76,512,765**

Notes: Adjustments to Total Electric Capital for exclusion of plant not recovered in rates and inclusion of shared assets from common plant.

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THIS SHEET IS IN USE FOR THE TRUE-UP RATE CALCULATION USING ACTUALS

Table C2

Table C2: Electric Capital Detail

Line No.	Project Name [A]	Electric Capital [B]	Assigned Function [C]
[1]	193952 - Operational Fiber Network	$ 40,589,499	General Plant
[2]	Production Plant	$ 15,981,531	Production Plant
[3]	Transmission Plant	$ 65,364,327	Transmission Plant
[4]	Distribution Plant	$ 75,278,214	Distribution Plant
[5]	General Plant	$ 42,277,141	General Plant
[6]	Intangible Plant	$ -	Intangible Plant
[7]			
[8]			
[9]			
[10]			
[11]	**Total Electric Capital by Project**	$ 239,490,711	
[12]	Cash-Funded Electric Capital	$ 117,102,264	Internal Records
[13]	Allocated Electric Capital	$ 6,853,752	Internal Records

Sources and Notes: [12] Cash-Funded Electric Capital is sourced from Internal record and is allocated to Transmission and General Plant. [13] Allocated Electric Capital is sourced from internal records and allocated to General Plant in the Electric Capital Summary tab. TFR Backup, [WP11 Misc Support] tab contains extracts from internal systems for source support.

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Table C3

Table C3: Debt Service and Interest

Thousands ($000)

Line No.	Bond Issue [A]	Electric Percentage [B]	Total Principal [C]	Total Interest [D]	Electric Principal [E] [C] x [B]	Electric Interest [F] [D] x [B]	Total Electric Debt [G] [E] + [F]
[1]	2005A	29.1%	$ 4,375	$ 2,577	$ 1,273	$ 750	$ 2,023
[2]	2006B	3.2%	$ 3,150	$ 1,864	$ 100	$ 59	$ 159
[3]	2007A	25.8%	$ 2,890	$ 1,349	$ 746	$ 348	$ 1,094
[4]	2008A	49.8%	$ 1,730	$ 1,270	$ 861	$ 632	$ 1,493
[5]	2009B	16.6%	$ 2,800	$ 2,733	$ 464	$ 453	$ 917
[6]	2009C	72.6%	$ 1,100	$ 2,841	$ 799	$ 2,063	$ 2,862
[7]	2009D	0.0%	$ 1,205	$ 2,878	$ -	$ -	$ -
[8]	2009E	0.0%	$ 488	$ 61	$ -	$ -	$ -
[9]	2010C	61.8%	$ 1,605	$ 1,246	$ 993	$ 771	$ 1,763
[10]	2010D	100.0%	$ -	$ 7,095	$ -	$ 7,095	$ 7,095
[11]	2012A	62.4%	$ 1,540	$ 1,356	$ 961	$ 847	$ 1,808
[12]	2012B	13.6%	$ -	$ -	$ -	$ -	$ -
[13]	2012C	0.0%	$ -	$ -	$ -	$ -	$ -
[14]	2013A	19.3%	$ -	$ -	$ -	$ -	$ -
[15]	2013B1	0.0%	$ -	$ -	$ -	$ -	$ -
[16]	2013B2	0.0%	$ -	$ -	$ -	$ -	$ -
[17]	2014A1	0.0%	$ -	$ -	$ -	$ -	$ -
[18]	2014A2	0.0%	$ -	$ -	$ -	$ -	$ -
[19]	2015A	24.5%	$ 1,925	$ 2,233	$ 472	$ 548	$ 1,020
[20]	2017A1	69.4%	$ 4,380	$ 3,162	$ 3,039	$ 2,194	$ 5,233
[21]	2017A2	12.5%	$ 2,010	$ 3,586	$ 251	$ 448	$ 699
[22]	2017A3	0.0%	$ -	$ -	$ -	$ -	$ -
[23]	CP Series A	0.0%	$ -	$ -	$ -	$ -	$ -

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Table C3

Table C3: Debt Service and Interest

Thousands ($000)

Line No.	Bond Issue [A]	Electric Percentage [B]	Total Principal [C]	Total Interest [D]	Electric Principal [E] [C] x [B]	Electric Interest [F] [D] x [B]	Total Electric Debt [G] [E] + [F]
[24]	CP Series B	0.0%	$ -	$ -	$ -	$ -	$ -
[25]	2018A1	46.9%	$ 22,435	$ 1,122	$ 10,531	$ 527	$ 11,058
[26]	2018A2	0.0%	$ 910	$ 1,655	$ -	$ -	$ -
[27]	2018A3	36.6%	$ 400	$ 124	$ 146	$ 45	$ 192
[28]	2018A4	0.0%	$ 1,315	$ 2,390	$ -	$ -	$ -
[29]	2019A	31.1%	$ -	$ 4,205	$ -	$ 1,308	$ 1,308
[30]	2020A	11.1%	$ 9,310	$ 6,789	$ 1,037	$ 756	$ 1,793
[31]	2020B	99.8%	$ 6,810	$ 1,010	$ 6,795	$ 1,007	$ 7,802
[32]	2020C	45.9%	$ 755	$ 3,361	$ 346	$ 1,541	$ 1,887
[33]	2021A	49.3%	$ 2,400	$ 1,097	$ 1,183	$ 541	$ 1,724
[34]	2021B	62.4%	$ 3,490	$ 7,313	$ 2,178	$ 4,563	$ 6,741
[35]	2022A	27.4%	$ 3,650	$ 5,190	$ 1,001	$ 1,423	$ 2,424
[36]	2022B	58.3%	$ -	$ 8,140	$ -	$ 4,746	$ 4,746
[37]	2023A	51.9%	$ -	$ 10,347	$ -	$ 5,374	$ 5,374
[38]	2023B	21.9%	$ 9,580	$ 7,806	$ 2,097	$ 1,708	$ 3,805
[39]	2024A	52.8%	$ -	$ 14,674	$ -	$ 7,748	$ 7,748
[40]	2024B	11.4%	$ 13,545	$ 4,328	$ 1,550	$ 495	$ 2,046
[41]			$ -	$ -	$ -	$ -	$ -
[42]			$ -	$ -	$ -	$ -	$ -
[43]			$ -	$ -	$ -	$ -	$ -
[44]			$ -	$ -	$ -	$ -	$ -
[45]			$ -	$ -	$ -	$ -	$ -
[46]			$ -	$ -	$ -	$ -	$ -

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Table C3

Table C3: Debt Service and Interest

Thousands ($000)

Line No.	Bond Issue [A]	Electric Percentage [B]	Total Principal [C]	Total Interest [D]	Electric Principal [E] [C] x [B]	Electric Interest [F] [D] x [B]	Total Electric Debt [G] [E] + [F]
[47]			$ -	$ -	$ -	$ -	$ -
[48]			$ -	$ -	$ -	$ -	$ -
[49]			$ -	$ -	$ -	$ -	$ -
[50]			$ -	$ -	$ -	$ -	$ -
[51]	Forecasted Debt		$ -	$ -	$ -	$ -	$ 40,556
[52]	**Total**		$ 103,798	$ 113,800	$ 36,824	$ 47,992	$ 125,372

Source: TFR Backup, [WP7 Debt Service and Interest] tab.

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Table C4

Table C4: Amortization of Premium or Discount

Line No.	Fiscal Year [A]	Account Number [B]	Account Name [C]	Sub Account [D]	Sub Account Cost Type [E]	Balance Year-To-Date [F]	
[1]	2026	428000	Amort of Debt Disc & Exp	90	MISCELLANEOUS ACCOUNTING GENERAL	$	625,917
[2]	2026	428010	Amort of Discount	1027	Amort of Discount -2005A	$	954
[3]	2026	428010	Amort of Discount	1034	Amort of Discount -2006B	$	88
[4]	2026	428010	Amort of Discount	1050	Amort of Discount -2010D	$	3,050
[5]	2026	428100	Amort of Loss on Reacq Debt	1036	2007B Amort Loss on Reac Debt	$	52,358
[6]	2026	428100	Amort of Loss on Reacq Debt	1039	2008B Amort Loss on Reac Debt	$	1,490
[7]	2026	428100	Amort of Loss on Reacq Debt	1042	2009A Amort Loss on Reac Debt	$	23,660
[8]	2026	428100	Amort of Loss on Reacq Debt	1044	2009C Amort Loss on Reac Debt	$	19,738
[9]	2026	428100	Amort of Loss on Reacq Debt	1047	2010A Amort Loss on Reac Debt	$	68,399
[10]	2026	428100	Amort of Loss on Reacq Debt	1051	2011A Amort Loss on Reac Debt	$	208,683
[11]	2026	428100	Amort of Loss on Reacq Debt	1053	2012B Amort Loss on Reac Debt	$	32,075
[12]	2026	428100	Amort of Loss on Reacq Debt	1055	2013A Amort Loss on Reac Debt	$	55,984
[13]	2026	428100	Amort of Loss on Reacq Debt	1066	2018A1 Amort Loss on Reac Debt	$	913,697
[14]	2026	428100	Amort of Loss on Reacq Debt	1068	2018A3 Amort Loss on Reac Debt	$	966
[15]	2026	429000	Amort of Prem on Debt-Cr	1043	Amort of Prem on Debt-2009B	$	(12,846)
[16]	2026	429000	Amort of Prem on Debt-Cr	1050	Amort of Prem on Debt-2010D	$	(48,193)
[17]	2026	429000	Amort of Prem on Debt-Cr	1060	Amort of Prem on Debt-2015A	$	(128,590)
[18]	2026	429000	Amort of Prem on Debt-Cr	1063	Amort of Prem on Debt-2017A-1	$	(522,217)
[19]	2026	429000	Amort of Prem on Debt-Cr	1064	Amort of Prem on Debt-2017A-2	$	(67,012)
[20]	2026	429000	Amort of Prem on Debt-Cr	1066	Amort of Prem on Debt-2018A1	$	(642,424)
[21]	2026	429000	Amort of Prem on Debt-Cr	1067	Amort of Prem on Debt-2018A2	$	-
[22]	2026	429000	Amort of Prem on Debt-Cr	1068	Amort of Prem on Debt-2018A3	$	(17,037)
[23]	2026	429000	Amort of Prem on Debt-Cr	1069	Amort of Prem on Debt-2018A4	$	-
[24]	2026	429000	Amort of Prem on Debt-Cr	1070	Amort of Prem on Debt-2019A	$	(818,842)
[25]	2026	429000	Amort of Prem on Debt-Cr	1071	Amort of Prem on Debt-2020A	$	(239,520)
[26]	2026	429000	Amort of Prem on Debt-Cr	1072	Amort of Prem on Debt-2020B	$	(1,322,540)
[27]	2026	429000	Amort of Prem on Debt-Cr	1073	Amort of Prem on Debt-2020C	$	(378,036)
[28]	2026	429000	Amort of Prem on Debt-Cr	1074	Amort of Prem on Debt-2021A	$	(351,444)
[29]	2026	429000	Amort of Prem on Debt-Cr	1075	Amort of Prem on Debt-2021B	$	(947,009)
[30]	2026	429000	Amort of Prem on Debt-Cr	1076	Amort of Prem on Debt-2022A	$	(188,504)

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Table C4

Table C4: Amortization of Premium or Discount

Line No.	Fiscal Year [A]	Account Number [B]	Account Name [C]	Sub Account [D]	Sub Account Cost Type [E]	Balance Year-To-Date [F]
[31]	2026	429000	Amort of Prem on Debt-Cr	1077	Amort of Prem on Debt-2022B	$ (332,563)
[32]	2026	429000	Amort of Prem on Debt-Cr	1078	Amort of Prem on Debt-2023A	$ (392,366)
[33]	2026	429000	Amort of Prem on Debt-Cr	1079	Amort of Prem on Debt-2023B	$ (194,779)
[34]	2026	429000	Amort of Prem on Debt-Cr	217	Amort of Prem on Debt-2024A	$ (648,692)
[35]	2026	429000	Amort of Prem on Debt-Cr	218	Amort of Prem on Debt-2024B	$ (64,448)
[36]	2026	429100	Amort of Gain on Reacq Debt	1016	2000A Amort Gain on Reac Debt	$ (37,678)
[37]	2026	429100	Amort of Gain on Reacq Debt	1071	2020A Amort Gain on Reac Debt	$ (41,949)
[38]	2026	429100	Amort of Gain on Reacq Debt	1072	2020B Amort Gain on Reac Debt	$ (88,717)
[39]	2026	429100	Amort of Gain on Reacq Debt	1074	2021A Amort Gain on Reac Debt	$ (401,568)
[40]	2026	429100	Amort of Gain on Reacq Debt	1076	2022A Amort Gain on Reac Debt	$ (202,963)
[41]	2026	429100	Amort of Gain on Reacq Debt	1079	2023B Amort Gain on Reac Debt	$ (126,180)
[42]	2026	429100	Amort of Gain on Reacq Debt	218	2024B Amort Gain on Reac Debt	$ (65,576)
[43]						$ 0
[51]	**Total Amortization of Premium or Discount**					$ (6,274,637)

Source: TFR Backup, [WP8 Amortization of prem or dis] & [WP9 Bond Issu Amort Exp Detail] tabs.

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Table E1

Table E1: Transmission Operations and Maintenance (O&M) Expenses

Line No.	Item	FERC Account No./Calculation	Actual Total [A]	Actual Labor-Related [B]
[1]	**Operation**			
[2]	Operation, Supervision and Engineering	560	$ 3,534,798	$ 4,220,107
[3]	Load Dispatching	561	$ 769,735	$ 396,146
[4]	Load Dispatch- Reliability	561.1	$ -	$ -
[5]	Load Dispatch- Monitor and Operate Transmission System	561.2	$ -	$ -
[6]	Load Dispatch- Transmission Service and Scheduling	561.3	$ -	$ -
[7]	Scheduling, System Control and Dispatch Services	561.4	$ -	$ -
[8]	Reliability, Planning and Standards Development	561.5	$ -	$ -
[9]	Transmission Service Studies	561.6	$ -	$ -
[10]	Generation Interconnection Studies	561.7	$ -	$ -
[11]	Reliability, Planning and Standards Development Services	561.8	$ -	$ -
[12]	Station Expenses	562	$ -	$ -
[13]	Overhead Line Expenses	563	$ 16,321	$ -
[14]	Underground Line Expenses	564	$ -	$ -
[15]	Transmission of Electricity by Others	565	$ -	$ -
[16]	Miscellaneous Transmission Expenses	566	$ 403,903	$ 366,173
[17]	Rents	567	$ -	$ -
[18]	**Total Operation**		$ 4,724,757	$ 4,982,426

Table E1

Table E1: Transmission Operations and Maintenance (O&M) Expenses

Line No.	Item	FERC Account No./Calculation	Actual Total [A]	Actual Labor-Related [B]
[19]	**Maintenance**			
[20]	Maintenance Supervision and Engineering	568	$ 184,405	$ 182,250
[21]	Maintenance of Structures	569	$ 611,843	$ 7,601
[22]	Maintenance of Computer Hardware	569.1	$ -	$ -
[23]	Maintenance of Computer Software	569.2	$ -	$ -
[24]	Maintenance of Communication Equipment	569.3	$ -	$ -
[25]	Maintenance of Miscellaneous Regional Transmission Plant	569.4	$ -	$ -
[26]	Maintenance of Station Equipment	570	$ 899,128	$ 520,080
[27]	Maintenance of Overhead Lines	571	$ 106,175	$ 85,814
[28]	Maintenance of Underground Lines	572	$ 129,426	$ 51,913
[29]	Maintenance of Miscellaneous Transmission Plant	573	$ -	$ -
[30]	**Total Maintenance**		$ 1,930,978	$ 847,658
[31]	**Total Operation and Maintenance Expense**	**[18] + [30]**	**$ 6,655,735**	**$ 5,830,084**

Source: TFR Backup, [WP2 O&M - A&G] tab.

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Table E1

Table E1: Transmission Operations and Maintenance (O&M) Expenses

Line No.	Item	FERC Account No./Calculation	Projected Total [C]	Projected Labor-Related [D]
[1]	**Operation**			
[2]	Operation, Supervision and Engineering	560	$ 4,943,609	$ 3,882,391
[3]	Load Dispatching	561	$ 2,255,582	$ 1,459,207
[4]	Load Dispatch- Reliability	561.1	$ -	$ -
[5]	Load Dispatch- Monitor and Operate Transmission System	561.2	$ -	$ -
[6]	Load Dispatch- Transmission Service and Scheduling	561.3	$ -	$ -
[7]	Scheduling, System Control and Dispatch Services	561.4	$ -	$ -
[8]	Reliability, Planning and Standards Development	561.5	$ -	$ -
[9]	Transmission Service Studies	561.6	$ -	$ -
[10]	Generation Interconnection Studies	561.7	$ -	$ -
[11]	Reliability, Planning and Standards Development Services	561.8	$ -	$ -
[12]	Station Expenses	562	$ -	$ -
[13]	Overhead Line Expenses	563	$ 23,843	$ -
[14]	Underground Line Expenses	564	$ -	$ -
[15]	Transmission of Electricity by Others	565	$ -	$ -
[16]	Miscellaneous Transmission Expenses	566	$ 734,293	$ 707,886
[17]	Rents	567	$ -	$ -
[18]	**Total Operation**		$ 7,957,327	$ 6,049,484

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Table E1

Table E1: Transmission Operations and Maintenance (O&M) Expenses

Line No.	Item	FERC Account No./Calculation	Projected Total [C]	Projected Labor-Related [D]
[19]	**Maintenance**			
[20]	Maintenance Supervision and Engineering	568	$ 226,101	$ 226,101
[21]	Maintenance of Structures	569	$ 271,648	$ 10,597
[22]	Maintenance of Computer Hardware	569.1	$ -	$ -
[23]	Maintenance of Computer Software	569.2	$ -	$ -
[24]	Maintenance of Communication Equipment	569.3	$ -	$ -
[25]	Maintenance of Miscellaneous Regional Transmission Plant	569.4	$ -	$ -
[26]	Maintenance of Station Equipment	570	$ 979,405	$ 816,215
[27]	Maintenance of Overhead Lines	571	$ 168,352	$ 168,352
[28]	Maintenance of Underground Lines	572	$ 43,760	$ 15,798
[29]	Maintenance of Miscellaneous Transmission Plant	573	$ -	$ -
[30]	**Total Maintenance**		$ 1,689,266	$ 1,237,063
[31]	**Total Operation and Maintenance Expense**	**[18] + [30]**	**$ 9,646,593**	**$ 7,286,547**

Source: TFR Backup, [WP2 O&M - A&G] tab.

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Table E2

Table E2: Administrative and General (A&G) Expenses

Line No.	Item	FERC Account No.	Actual Account Balance [A]	Projected Account Balance [B]
[1]	Administrative and General Salaries	920	$ 27,211,447	$ 28,799,691
[2]	Office Supplies and Expenses	921	$ 14,837,289	$ 18,288,293
[3]	Administrative Expenses Transferred-Credit (*enter negative*)	922	$ (5,065,922)	$ (5,708,488)
[4]	Outside Services Employed	923	$ 4,536,645	$ 3,659,561
[5]	Property Insurance	924	$ 2,775,317	$ 3,834,500
[6]	Injuries and Damage	925	$ 14,233	$ 136,963
[7]	Employee Pensions and Benefits	926	$ 26,307,091	$ 29,590,865
[8]	Franchise Requirements	927		$ -
[9]	Regulatory Commission Expenses	928	$ 197,736	$ 214,146
[10]	Duplicate Charges - Credit (*enter negative*)	929		$ -
[11]	General Advertising Expenses	930.1	$ 266,405	$ -
[12]	Miscellaneous General Expenses	930.2	$ 287,979	$ 219,988
[13]	Rents	931		$ -
[14]	Maintenance of General Plant	932	$ 3,604,719	$ 5,811,614
[15]	**Total Administrative and General Expense**		$ 74,972,938	$ 84,847,133

Source: TFR Backup, [WP2 O&M - A&G] tab.

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Table E3

Table E3: Revenue Credits

Line No.	Item	Source/Calculation	FERC Account No.	Total Transmission
	Sales for Resale			
[1]	Bundled Non-RQ Sales for Resale		447	$ -
[2]	Bundled Sales for Resale included in Divisor		447	$ -
[3]	**Total Sales for Resale**	**[1] + [2]**		$ -
	Rent from Electric Property			
[4]			454	$ -
[5]			454	$ -
[6]			454	$ -
[7]			454	$ -
[8]			454	$ -
[9]			454	$ -
[10]			454	$ -
[11]			454	$ -
[12]			454	$ -
[13]			454	$ -
[14]	**Total Rent from Electric Property**	**SUM([4]:[13])**		$ -
[15]	**Other Electric Revenues Credited**	**Table E4: [15]**	456	$ -
[16]	**TOTAL REVENUE CREDITS**	**[3] + [14] + [15]**		$ -

Source: TFR Backup, [WP10 Account 456.1] tab.

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Table E4

Table E4: Other Electric Revenues

Line No.	Description	Assignment		Total Revenue
[1]	Firm Network	Divisor	$	-
[2]	Long Term Firm	Divisor	$	-
[3]	Other Long Term Firm	Divisor	$	-
[4]	Short Term Firm Point To Point	Credit	$	-
[5]	Non Firm	Credit	$	-
[6]	Other Service	Divisor	$	-
[7]	Distribution Wheeling Fees (Direct)	Divisor	$	102,908
[8]	Non-Firm Off-System Revenues	Credit	$	-
[9]	Schedule 4 - Energy Imbalance Service	Divisor	$	1,547,433
[10]				
[11]			$	-
[12]			$	-
[13]			$	-
[14]			$	-
[15]	**TOTAL REVENUE CREDIT**		$	-

Source: TFR Backup, [WP10 Account 456.1] tab.

CSU Formula Rate Implementation Protocols

Section I. Annual Update

1. The Formula Rate Template of Colorado Springs Utilities ("CSU") set forth in Attachment H, of the Southwest Power Pool ("SPP") Open Access Transmission Tariff and these Formula Rate Implementation Protocols ("Protocols") together comprise the filed rate ("Formula Rate") of CSU for transmission service in the CSU zone of the SPP footprint. CSU must follow the instructions specified in the Formula Rate to calculate its Annual Transmission Revenue Requirements ("ATRR") and the rates for Network Integration Transmission Service ("NITS") and Point-to-Point Transmission Service in the CSU zone of the SPP footprint, as well as the ATRR for Base Plan Upgrades and other network upgrades. The initial ATRR and the initial rates will be in effect for a partial year from the effective date of CSU's transfer of operational control of its transmission facilities to SPP until December 31, 2026.

2. The Formula Rate shall be applicable to service on and after January 1 of each calendar year through December 31 of the following calendar year ("Rate Year"), and subject to review as provided in these Protocols.

3. On or before September 1 of each calendar year, CSU shall:

   a) Recalculate the ATRR and the rates for zonal NITS and zonal Point-to-Point Transmission Service for the new Rate Year in accordance with the Formula Rate ("Annual Update"); and

   b) Provide its Annual Update to SPP and cause such information to be posted on SPP's website and OASIS. Within ten (10) days of such posting, CSU shall provide notice of such posting to all parties on an SPP email exploder list. Interested Parties can contact SPP to subscribe to the SPP "exploder list." For purposes of these Protocols, the term Interested Parties includes, but is not limited to customers under the SPP OATT, state utility regulatory commissions, consumer advocacy agencies, and state attorneys general.

4. If the date for posting the Annual Update falls on a weekend or a holiday recognized by the Federal Energy Regulatory Commission ("FERC"), then the posting shall be due on the next business day. The date on which any such posting occurs shall be that year's "Publication Date". Any delay in the Publication Date will result in an equivalent extension of time for the submission of Information Requests discussed in Section III of these Protocols.

5. CSU shall submit to FERC an Informational Filing as provided in Section VI of these Protocols.

6. The Annual Update for the Rate Year shall:

   a. Include a workable data-populated Formula Rate Template and underlying workpapers in native format with all formulas and links intact;

   b. Provide the Formula Rate calculations and all inputs thereto, as well as supporting documentation and workpapers for data that are used;

   c. Provide sufficient information to enable Interested Parties to replicate the calculation;

   d. Identify all material adjustments made to the Formula Rate data in determining formula inputs;

   e. With respect to any change in accounting that affects inputs to the Formula Rate or the resulting charges billed under the Formula Rate ("Accounting Change"):

      i. Identify any Accounting Changes, including:

         1. the initial implementation of an accounting standard or policy;

         2. the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

         3. correction of errors and prior period adjustments that impact the calculation;

         4. the implementation of new estimation methods or policies;

      ii. Identify items included in the calculation at an amount other than on a historic cost basis (e.g., fair value adjustments);

      iii. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs;

      iv. Provide, for each item identified pursuant to items I.6.e.i - I.6.e.iii of these protocols, a narrative explanation of the individual impact of such changes on the calculation.

Section II. Review of Annual Update

1. CSU shall hold an open meeting among Interested Parties ("Annual Meeting") no sooner than seven (7) days and no later than thirty (30) days from the Annual Update Publication Date. No less than seven (7) days prior to such Annual Meeting, CSU shall provide notice on SPP's website and OASIS of the time, date, and location of the Annual Meeting and request SPP provide notice of such meeting to an SPP email exploder list. The Annual Meeting will be hosted by CSU in the forum of its choice which may include video conferencing, webinar, internet conferencing, phone conferencing, in person, or other similar options. CSU shall provide remote access for Interested Parties to participate in the meeting. The Annual Meeting shall (i) permit CSU to explain and

clarify its Annual Update and (ii) provide Interested Parties an opportunity to seek information and clarification from CSU about the Annual Update.

2. Each year CSU shall endeavor to coordinate with other Transmission Owners in SPP using formula rates to establish revenue requirements for recovery of the costs of transmission projects that utilize the same regional cost sharing mechanism and hold a joint informational meeting to enable all Interested Parties to understand how those transmission owners are implementing their formula rates for recovering the costs of such projects.

Section III. Information Exchange Procedures

1. Each Annual Update shall be subject to the following information exchange procedures ("Information Exchange Procedures"):

   a. Interested Parties shall have until October 31 following the Publication Date (unless such period is extended with the written consent of CSU or by FERC order) to serve reasonable information and document requests on CSU ("Information Exchange Period"). If October 31 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all information and document requests shall be extended to the next business day. Such information and document requests shall be limited to what is necessary to determine:

      i. the extent, effect or impact of an Accounting Change;

      ii. whether the Annual Update fails to include data properly recorded in accordance with these protocols;

      iii. the proper application of the Formula Rate and procedures in these protocols;

      iv. the accuracy of data and consistency with the Formula Rate of the calculations shown in the Annual Update;

      v. the prudence of actual costs and expenditures, including the prudence of CSU's procurement methods and cost control methodologies;

      vi. the effect of any change to the underlying FERC Uniform System of Accounts; or

      vii. any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

   The information and document requests shall not otherwise be directed to ascertaining whether the Formula Rate is just and reasonable.

2. CSU shall make a good faith effort to respond to information and document requests within seven (7) business days of receipt of such requests. Information requests received after 4 p.m. Central Prevailing Time shall be considered received the next business day.

3. CSU will cause to be posted on SPP's website, OASIS and CSU's website (csu.org) all information requests from Interested Parties and CSU's response(s) to such requests; except, however, if responses to information and document requests include material deemed by CSU to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by CSU and the requesting party.

4. CSU shall not claim that responses to information and document requests provided pursuant to these protocols are subject to any settlement privilege, in any subsequent FERC proceeding addressing CSU's Annual Update.

5. No later than December 20th of each year, CSU, upon final approval of CSU's local regulatory body, will provide SPP for posting on SPP's website and OASIS CSU's Annual Update for SPP to include in the Zonal ATRR and resulting rates to become effective January 1st of the following calendar year.

Section IV. Challenge Procedures

1. Interested Parties shall have until October 31 (unless such period is extended with the written consent of CSU or by FERC order) to review the inputs, supporting explanations, allocations and calculations and to notify CSU in writing, which may be made electronically, of any specific Informal Challenges to the Annual Update. The period of time from the Publication Dates until the date Informal Challenges are due shall be referred to as the Review Period. If the date for submitting Informal Challenges falls on a weekend or a holiday recognized by FERC, the deadline for submitting all Informal Challenges shall be extended to the next business day. Failure to pursue an issue through an Informal Challenge shall not bar pursuit of that issue as part of a Formal Challenge with respect to the same Annual Update as long as the Interested Party has included at least one issue as part of an Informal Challenge with respect to that Annual Update. If the Interested Party has not included any issues as part of an Informal Challenge for an Annual Update, the Interested Party is barred from pursuing a Formal Challenge with respect to any issue for that Annual Update but is not barred from pursuing an issue or from lodging a Formal Challenge as to such issue as it relates to a subsequent Annual Update.

2. A party submitting an Informal Challenge to CSU must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge. CSU shall make a good faith effort to respond to any Informal Challenge within fifteen (15) business days of notification of such challenge. CSU, and where applicable, SPP, shall appoint a senior representative to work with the party that submitted the Informal Challenge (or its representative) toward a resolution of the challenge. If CSU disagrees with such challenge, CSU will provide the Interested Party(ies) with an explanation supporting the inputs, supporting explanations, allocations, calculations, or other information following the Publication Dates.

3. Informal Challenges shall be subject to the resolution procedures and limitations in this Section IV. Formal Challenges shall be filed pursuant to these Protocols and shall satisfy the requirements set forth in section IV.4, IV.7, IV.8, and IV.9.

4. Informal Challenges shall be limited to all issues that may be necessary to determine: (1) the extent or effect of an Accounting Change; (2) whether the Annual Update fails to include data properly recorded in accordance with these protocols; (3) the proper application of the Formula Rate and procedures in these protocols; (4) the accuracy of data and consistency with the Formula Rate of the calculations shown in the Annual Update; (5) the prudence of actual costs and expenditures; (6) the effect of any change to the underlying FERC Uniform System of Accounts; or (7) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula. Any Interested Party seeking to challenge the prudence of actual costs or expenditures shall first raise the matter with CSU in accordance with this Section IV before pursuing a Formal Challenge.

5. CSU will cause to be posted on SPP's website and OASIS all Informal Challenges from Interested Parties and CSU's response(s) to such Informal Challenges; except, however, if Informal Challenges or responses to Informal Challenges include material deemed by CSU to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by CSU and the requesting party.

6. Any changes or adjustments to the Annual Update resulting from the Information Exchange and Informal Challenge processes that are agreed to by CSU will be reported in the Informational Filing required pursuant to Section VI of these protocols and will be reflected in the Annual Update for the following Rate Year, as discussed in Section V of these Protocols.

7. Interested Parties shall have until March 31 (unless such date is extended with the written consent of CSU to continue efforts to resolve the Informal Challenge) to file any Formal Challenges to the Annual Update posted in the previous calendar year.

8. Formal Challenges shall be filed pursuant to these Protocols and shall satisfy all of the following requirements.
    a. A Formal Challenge shall:
        i. Clearly identify the action or inaction which is alleged to violate the filed rate formula or Protocols;
        ii. Explain how the action or inaction violates the filed rate formula or Protocols;
        iii. Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:
            1. The extent or effect of an Accounting Change;
            2. Whether the Annual Update fails to include data properly recorded in accordance with these Protocols;
            3. The proper application of the Formula Rate and procedures in these Protocols;
            4. The accuracy of data and consistency with the Formula Rate of the charges shown in the Annual Update;
            5. The prudence of actual costs and expenditures.
            6. The effect of any change to the underlying FERC Uniform System of Accounts; or
            7. Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula
        iv. Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;
        v. State whether the issues presented are pending in an existing FERC proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;
        vi. State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;
        vii. Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and
        viii. State whether the filing party utilized the Informal Challenge procedures described in these Protocols with regard to any issue.

b. Any person filing a Formal Challenge must serve a copy of the Formal Challenge on CSU. Service to CSU must be simultaneous with filing at the Commission. Simultaneous service can be accomplished by electronic mail in accordance with 18 C.F.R. § 385.2010(f)(3), facsimile, express delivery, or messenger. The party filing the Formal Challenge shall serve the individual listed as the contact person on CSU's Informational Filing required under Section VI of these Protocols.

9. All Formal Challenges shall be served on CSU on the date of such filing as specified in Section IV.8.b above. A Formal Challenge shall be filed in the same docket as CSU's Informational Filing discussed in Section VI of these protocols. CSU shall respond to the Formal Challenge by the deadline established by FERC. A party may not pursue a Formal Challenge if that party did not submit any Informal Challenge during the applicable Review Period.

10. In any proceeding initiated by FERC concerning the Annual Update or in response to a Formal Challenge, CSU shall bear the burden, consistent with section 205 of the Federal Power Act, of proving that it has correctly applied the terms of the Formula Rate consistent with these protocols, and that it followed the applicable requirements and procedures in these Protocols. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

11. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of CSU to request SPP to file unilaterally, pursuant to Federal Power Act section 205 and the regulations thereunder, to change the Formula Rate or any of its inputs (including, but not limited to, rate of return and transmission incentive rate treatment), or to replace the Formula Rate with a stated rate, or the right of any other party to request such changes pursuant to section 206 of the Federal Power Act and the regulations thereunder.

12. No party shall seek to modify the Formula Rate under the Challenge Procedures set forth in these Protocols, and the Annual Update shall not be subject to challenge by anyone for the purpose of modifying the Formula Rate. Any modifications to the Formula Rate will require, as applicable, a Federal Power Act section 205 or section 206 filing.

13. Any Interested Party seeking changes to the application of the Formula Rate due to a change in the FERC Uniform System of Accounts, shall first raise the matter with CSU in accordance with this Section IV before pursuing a Formal Challenge.

14. The implementation of any changes or adjustments resulting from any Formal Challenge made with FERC will be subject to: (1) approval by CSU's Board of Directors; and (2) SPP Tariff Section 39.1. Further, nothing herein is intended to alter, and does not supersede, sections 3.10, 3.11, and 3.12 of the Southwest Power Pool Membership Agreement.

Section V. Changes to Annual Update

1. Except as provided in Section IV.6 of these Protocols, any changes to the data inputs, including but not limited to changes as the result of any FERC proceeding to consider the Annual Update, or as a result of the procedures set forth herein, shall be incorporated into the Formula Rate and the charges produced by the Formula Rate in the Annual Update for the next Rate Year. This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments. Interest on any refund or surcharge, if applicable, shall be calculated in accordance with the 18 C.F.R. § 35.19a

2. In the event that CSU is required by applicable law to correct an error, CSU shall correct such error in good faith and without regard to whether the correction increases or decreases CSU's revenue requirements, in a manner consistent with FERC's regulations. Nothing in these Protocols should or may be construed as preventing Interested Parties or the FERC from protesting such correction as inappropriate

Section VI. Informational Filings

1. By January 15 of each year, CSU shall submit to FERC an informational filing ("Informational Filing") of its Annual Update for the Rate Year. This Informational Filing must include the information that is reasonably necessary to determine: (1) that input data under the Formula Rate are properly recorded in any underlying workpapers; (2) that CSU has properly applied the Formula Rate and these procedures; (3) the accuracy of data and the consistency with the Formula Rate of the ATRR and rates under review; and (4) the extent of accounting changes that affect Formula Rate inputs. The Informational Filing must also describe any corrections or adjustments made during that period and must describe all aspects of the Formula Rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures. Within five (5) days of such Informational Filing, CSU shall request SPP provide notice of the Informational Filing via an SPP email exploder list and by posting the docket number assigned to CSU's Informational Filing on SPP's website and OASIS.
2. Any challenges to the implementation of the Attachment H - CSU Formula Rate must be made through the Challenge Procedures described in Section IV of these Protocols and not in response to the Informational Filing.